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EXHIBITS
FOR
E-01345A-03-0437

<u>BARCODE 0000020461</u>

APS 5-27
APS 33-39

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0000020460: ACPA 1-4, AECC 1, 2, AECC/PD/FEA/K 1-3, APS 1-4

0000020462: APS-R 1-15

0000020463: APS-R 16-22, APS-SD 1-4, ASP-SR 1-3, AUIA, AUIA-S, AZCA 1-5 & 7-10 (6 NOT USED) CNE/SEL 1-5, DOME VALLEY, FEA 1 & 2, GLEASON 1, IBEW 1, KROGER 1, MESQUITE 1 & 2, MUNDELL 1

0000020464: PPL 1 & 2, RUCO 1-15, SOUTHWESTERN POWER 1 & 2 STAFF 1-9

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The following exhibits were hand delivered to you earlier today:

✓ACPA	1 through 4	
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APS	1 through 27 and 33 through 39	Note: APS 28 – 32 are late-filed
APS-R	1 through 22	
APS-SD	1 through 4	
APS-SR	1 through 3	
AUIA	1	
AUIA-S	1	
AZCA	1 through 5 and 7 through 10	Note: AZCA 6 was not utilized
CNE/SEL	1 through 5	
Dome Valley	1	
FEA	1 and 2	
Gleason	1	
IBEW	1	Note: IBEW 1 is not listed on any index page
Kroger	1	
Mesquite	1 and 2	
Mundell	1	
PPL	1 and 2	
RUCO	1 through 15	
Southwestern Power	1 and 2	
Staff	1 through 32	
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APS-5
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DIRECT TESTIMONY OF LAURA L. ROCKENBERGER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-___

June 27, 2003

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DIRECT TESTIMONY OF LAURA L. ROCKENBERGER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-____)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Laura L. Rockenberger. My business address is 400 North Fifth Street, Phoenix, Arizona, 85072-3999.

Q. WHAT IS YOUR POSITION WITH ARIZONA PUBLIC SERVICE COMPANY?

A. I am the Group Leader of Accounting Operations for Arizona Public Service Company ("APS" or "Company"). My educational background and professional qualifications, as well as my professional experience, are set forth in Appendix A, which is attached to this testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses four accounting-related topics to support the Company's rate case application. First, I sponsor the Reproduction[1] Cost New ("RCN") study for Schedule B-4 of the Arizona Corporation Commission's ("Commission") Standard Filing Requirements ("SFR") and the various elements of the adjusted Reproduction Cost New Less Depreciation ("RCND") rate base (SFR Schedules B-3 and B-4a). These are summarized in SFR Schedule B-l. Second, my testimony explains the Cash Working Capital component of APS' Allowance for Working Capital (SFR Schedule B-5, Line 1) which was calculated following the lead/lag study method required by the

[1] "Reproduction Cost" or "Reconstructed Cost" are used interchangeably.

Commission in Decision No. 55931 (April 1, 1988). Third, I explain the process used to arrive at the Company's proposed depreciation and amortization rates. Finally, I will explain the effects of APS' adopting Statement of Financial Accounting Standards No. 143 ("SFAS 143"), which addresses Asset Retirement Obligations ("ARO"), and how APS, as a regulated public utility, must account for ARO for financial reporting purposes.

II. SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. To aid the Commission in its determination of the "fair value" of APS' properties devoted to public service, I am presenting the results of the Company's most recent RCN study. This study, which follows the same methodology used in prior studies filed with and accepted by this Commission, establishes the RCN value of gross utility plant to be approximately $13.6 billion as of December 31, 2002, the end of the test year. After adjusting this RCN value of gross utility plant to reflect accumulated depreciation, combining it with the other elements of rate base, including pro forma adjustments, and determining the jurisdictional allocation for retail customers, the total Commission jurisdictional RCND rate base is approximately $6.7 billion. The precise value is shown in SFR Schedule B-1, line 19.

My testimony then presents the calculation of the allowance for working capital, which includes a cash working capital component determined using the lead/lag study methodology required by Decision No. 55931. Based on total APS test year balances, the calculation of a reasonable allowance for working capital results in an addition to rate base of $175.7 million, of which roughly $54.1

million reflects net cash working capital calculated using the lead/lag study. The balance of the rate base increase for working capital requirements is primarily attributable to non-cash operating reserves, as well as inventories of fuel, materials and supplies.

The third subject that I address is depreciation and amortization. I will discuss the depreciation study that APS conducted, including the purpose of the study, the consulting firm used, and methodology for determining depreciation rates for the rate case. I will also discuss amortization rates proposed by the Company.

Finally, I will address the recent accounting standard on ARO, which is embodied in SFAS 143, which must be followed when determining the appropriate treatment of legal obligations associated with the retirement of long-lived assets. These include such obligations as decommissioning or removal costs for certain generating plants. I will discuss the major differences between APS' current practices and the new practices required under SFAS 143.

III. REPRODUCTION COST NEW STUDY

Q. WERE SFR SCHEDULES B-3, B-4 AND B-4A PREPARED AT YOUR DIRECTION AND UNDER YOUR SUPERVISION AND CONTROL?

A. Yes, they were.

Q. WHAT IS MEANT BY THE TERMS "RCN" AND "RCND" AS USED IN YOUR TESTIMONY?

A. A.A.C. R14-2-103(A)(3)(n) ("Rule 103") defines "Reconstructed Cost New" Less Depreciation or RCND as:

> An amount consisting of the depreciated reconstruction cost new of property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments. Contributions and advances in aid of construction, if recorded in the accounts of the public service corporation, shall be increased to a reconstruction new basis.

Thus, RCN refers to the estimated costs that would be incurred if the utility properties of APS that were devoted to public service as of December 31, 2002 were to be reproduced or reconstructed as new properties using current cost levels. RCND is a net amount that results after deducting accumulated depreciation and amortization (both of which are also restated in current dollars) from the RCN amount.

Q. WHAT IS SHOWN ON SFR SCHEDULE B-4?

A. SFR Schedule B-4 presents the RCN and RCND amounts of APS' utility properties. These amounts were determined using an RCN Study performed by the Company.

Q. WOULD YOU BRIEFLY DESCRIBE THE PROCEDURES YOU FOLLOWED IN CONDUCTING THE RCN STUDY?

A. Consistent with Rule 103, the RCN study that supports SFR Schedule B-4 was conducted by taking depreciable plant at original cost by FERC account,[2] by vintage year, and adding back Contributions in Aid of Construction ("CIAC") at original cost. Electric and gas utilities are required by the USOA to subtract CIAC from original cost plant-in-service rather than record it as a separate liability account, as is done by water and sewer utilities. This amount was multiplied by the Handy-Whitman index factor, based on vintage year, to arrive at RCN before CIAC adjustment. CIAC was also multiplied by the appropriate

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[2] The Commission has adopted the FERC Uniform System of Accounts ("USOA") in A.A.C. R14-2-212(G).

Handy-Whitman index. The adjusted CIAC was added to the RCN determined before CIAC adjustment to arrive at the final RCN number shown in column (a) of SFR Schedule B-4.

Q. WOULD YOU EXPLAIN IN MORE DETAIL THE CONSIDERATION THAT YOU GAVE TO CONTRIBUTIONS IN AID OF CONSTRUCTION IN DETERMINING RCN?

A. Yes. CIAC is generally cash paid to APS by third parties for construction of facilities to be owned by APS. Sometimes, it may also include property donated to the Company to provide service. Line extensions are the most common source of CIAC. As with original cost plant, CIAC is indexed using the Handy-Whitman Index as required by Rule 103 to arrive at Reproduction Cost New. A summary of CIAC is provided in column (b) of Attachment LLR-1.

Q. WHAT IS THE HANDY-WHITMAN INDEX?

A. The Handy-Whitman Index is recognized by the utility industry as being essentially equivalent to a Consumers Price Index for electric utility property. It compares the current cost of constructing electric utility property with past construction costs and presents the comparison in the form of a cost index. For example, assume that transmission towers and fixtures were purchased by APS in 1985 at an original cost of $400,000. To determine RCN, the original cost would be multiplied by the appropriate Handy-Whitman index factor for towers and fixtures. In this case, the index factor is determined by dividing the current year index of 347 for 2002 by the vintage year index of 245 for 1985, or 347/245, which equals 1.416. The index factor of 1.416 multiplied by the original cost of $400,000 equals the current reproduction cost or RCN of $566,400.

Q. **WERE ALL ASSETS INDEXED AS YOU JUST DESCRIBED?**

A. No, land and land rights, intangibles, capitalized leases, and leasehold improvements are included in RCN at their original cost levels only, consistent with previous treatment of these assets by the Commission.

Q. **PLEASE DEFINE INTANGIBLES AND DESCRIBE THE AMOUNT OF INTANGIBLES THAT ARE INCLUDED IN RCN AS SHOWN ON SFR SCHEDULE B-4?**

A. Intangibles are assets that provide future economic benefit but have no physical substance. Examples include patents and computer software. APS' intangible plant is included in column (a), line 4 of SFR Schedule B-4 at its original cost of $202,508,000 on December 31, 2002.

Q. **BASED ON YOUR STUDY, WHAT IS THE RCN OF APS' UTILITY PROPERTY DEVOTED TO SERVICE TO THE PUBLIC AS OF THE END OF THE TEST YEAR?**

A. Total RCN for APS' utility property is $13,596,926,000 including the $202,508,000 of intangible plant that I just discussed. This total amount is shown in column (c) of Attachment LLR-1, and in column (a) of SFR Schedule B-4.

Q. **WOULD YOU EXPLAIN HOW RCND WAS CALCULATED AS SHOWN ON SFR SCHEDULE B-4?**

A. Yes. RCN by FERC account (or Plant account) number is shown in column (a) of SFR Schedule B-4. To arrive at RCND, RCN is multiplied by a "condition percent," which is shown in column (b). RCND is shown in column (c). The condition percent used to convert RCN to RCND is calculated by first taking the original cost less accumulated depreciation (in other words, the net book value) for all depreciable plant by FERC account. This is divided by the original cost for each FERC account to arrive at condition percent, also known as a net book value percent. Thus, the condition percent is the percentage that results when one compares original cost less accumulated depreciation and the original cost of plant in service.

For example, using the same hypothetical that I used earlier, assume again that transmission towers and fixtures have an original cost of $400,000, and assume accumulated depreciation of $250,000. The original cost less accumulated depreciation would be $150,000, which is $400,000 minus $250,000. Also, assume the towers and fixtures were purchased in 1985 and have a RCN value of $566,400. Using these assumptions, the condition percent is calculated by dividing original cost less accumulated depreciation by original cost, or $150,000/$400,000, resulting in 37.5%. Multiplying RCN by the condition percent yields RCND. In this hypothetical, $566,400 x 37.5% = $212,400.

Q. WOULD YOU PLEASE EXPLAIN SFR SCHEDULE B-4A?

A. SFR Schedule B-4A shows the computation of adjusted jurisdictional RCND rate base as of December 31, 2002. Column (a) presents data for Total RCND rate base. Mr. Propper has provided the jurisdictional allocations of the Electric RCND rate base between "ACC" and "Other" which is presented in columns (b) and (c) respectively.

Q. HOW DID YOU ARRIVE AT THE AMOUNTS SHOWN ON LINES 9 THROUGH 23 OF SFR SCHEDULE B-4A?

A. The amounts shown on lines 9 through 23 of SFR Schedule B-4A for other rate base elements, were obtained from SFR Schedule B-1, column (a), which is sponsored by Mr. Froggatt. As in past presentations and consistent with past Commission practice, the RCND of these rate base elements are stated at their original cost levels.

Q. WOULD YOU PLEASE EXPLAIN LINES 25 AND 26 OF SFR SCHEDULE B-4A?

A. Yes. The amounts shown on line 25 represent the RCND rate base on December 31, 2002. However, as explained in APS witness Donald G. Robinson's direct testimony, the end of test year data needs to be adjusted to more closely reflect the value of certain items of property when the proposed rates become effective. Therefore, it was necessary to reflect in the RCND rate base, the pro forma rate base adjustments described by Mr. Robinson. The RCND amounts of the pro forma adjustments are shown in detail on SFR Schedule B-3 and their total shown on line 26 of SFR Schedule B-4A.

Q. WHAT THEN IS THE TOTAL ADJUSTED RCND RATE BASE?

A. The total RCND rate base, as adjusted is $6.7 billion. This is shown in SFR Schedule B-4A, column (a), line 27.

Q. PLEASE EXPLAIN HOW YOU COMPUTED COLUMNS (B) THROUGH (E) ON SFR SCHEDULE B-4A TO REFLECT THE JURISDICTIONAL ALLOCATION?

A. The jurisdictional allocation of the RCND rate base elements between state retail service (the Commission) and other jurisdictions (primarily FERC) was made by applying the original cost jurisdiction relationships derived from Schedule GJ, which is sponsored by APS witness Alan Propper. The relationships of the allocations shown on line 2, excluding the Southern California Edison ("SCE") 500 kV column, were used to allocate between jurisdictions on line 8. Total RCN excludes the SCE 500 kV amounts. The data shown in column (d) for the SCE 500 kV line represents known or directly computed information. The jurisdictional allocations of lines 9 through 23, because they are stated at original cost, were obtained directly from Schedule GJ.

Q. WOULD YOU PLEASE SUMMARIZE THE JURISDICTIONAL ALLOCATION OF THE RCND RATE BASE AS OF DECEMBER 31, 2002 AFTER MAKING THE PRO FORMA ADJUSTMENTS?

A. Yes. The Total Commission-jurisdictional RCND rate base after adjustments is $6.7 billion (SFR Schedule B-4A, column (b), line 27). After pro forma adjustments, the Total All Other RCND rate base is $17 million (SFR Schedule B-4A, column (c)). The sum of columns (b) and (c) equals the Total RCND rate base shown in column (a).

Q. WOULD YOU PLEASE DISCUSS SFR SCHEDULE B-3?

A. SFR Schedule B-3 presents the pro forma adjustments to the RCND rate base. The pro forma adjustments reflect each of the rate base adjustments that are discussed in more detail in Mr. Robinson's testimony.

IV. <u>ALLOWANCE FOR WORKING CAPITAL</u>

Q. WHAT IS THE ALLOWANCE FOR WORKING CAPITAL SHOWN ON SFR SCHEDULE B-1?

A. It is an allowance for the amount of money that the utility has furnished from its own funds for the purpose of satisfying ordinary business requirements, such as cash required to maintain minimum bank balances and cash needed to bridge the gap between the time expenses are paid by APS and the time revenues are collected from customers. The allowance for working capital includes cash working capital as well as certain inventories and non-cash items as shown on page one of SFR Schedule B-5 .

Q. **PLEASE DEFINE CASH WORKING CAPITAL.**

A. Cash working capital is a component of the allowance for working capital. As used in my testimony, cash working capital is the net amount of funds, provided by either investors (positive) or customers (negative), needed to meet daily cash operating expenses. The method used to estimate cash working capital is known as a lead/lag study method, which is a method frequently used in the utility industry.

Q. **HAVE YOU PREPARED A SCHEDULE SETTING FORTH A SUMMARY OF THE RESULTS OF THE STUDY?**

A. Yes. Attachment LLR-2 was prepared to summarize the results of the lead/lag study and the cash working capital requirement for the test year that ended December 31, 2002.

Q. **WHAT APPROACH TO MEASURING CASH WORKING CAPITAL IS TAKEN IN THE LEAD/LAG STUDY BEING PRESENTED?**

A. A lead/lag study measures the difference in time between (1) the time service is rendered until the revenues for that service are received, and (2) the time that fuel, purchased power, labor, materials, services, and other similar items are used in providing service until they are paid for by APS. The difference between each of these two periods is expressed as a number of days. The net number of days (either positive or negative) times the average daily operating expenses that are included in the calculation produces the measure of cash working capital required for those operating expenses. Certain other more or less static cash requirements, such as special deposits and working funds, and non rate-based elements of rate-based components (such as depreciation and amortization) are added to that amount to arrive at cash working capital.

Q. WOULD YOU PLEASE SUMMARIZE ATTACHMENT LLR-2?

A. Attachment LLR-2, shows the components of the net cash working capital provided by operations. The net cash working capital of $54,098,000, which represents an increase in the overall working capital requirement, shown on Attachment LLR-2 means that current operations require increased amounts of capital over what is currently reflected in rate base.

Q. WOULD YOU PLEASE SUMMARIZE ATTACHMENT LLR-3?

A. Attachment LLR-3 shows the detailed components of the cash working capital required for operating expenses. It sets forth the cash working capital requirement for operating expenses by major categories of unadjusted test year operating expense. The test year amount of expense (column 1) is multiplied by the cash working capital factor (column 5) to arrive at the average daily cash working capital requirement (column 6). Column 2 shows the average days of delay (41.81 days) from the time service is rendered until payment is received from customers. Column 3 shows the average days of delay in payment of expenses from the time each category of expense was incurred.

Column 4 shows the net lag days (revenue lag less expense lag). The existence of positive net lag days indicates the number of days investors must on average provide additional funds to pay for the expense before it is recovered from customers. Negative net lag days indicate that the collection of revenues for service rendered on the day the expense was incurred will occur prior to that expense being paid. Column 5, the cash working capital factor, is derived by dividing net lag days in Column 4 by 365.

Q. **HOW IS THE AVERAGE REVENUE LAG PERIOD CALCULATED?**

A. There are three components to the average customer revenue lag period. The first component measured is the average period that service is provided to the customer before the meter is read. APS reads its meters once a month, therefore, the average time between meter reading dates, and thus the average service period between each meter read, is 30.42 days (365 days/12 months). Dividing the service period by two produces the average period from the time service was rendered until the meter read (15.21 days). The second component measured is the average period from the time the meter is read until the customer is billed (5.1 days). The third component is the average days from the time the customer is billed until payment is received (22.21 days). The days from the billing date to the collection date for retail customers was determined by analyzing APS' billing process and calculating the average days of revenue that remained in accounts receivable at the end of each month. The summation of these three components produces the total average days of delay for recovering operating expenses from customers (15.21 + 5.1 + 22.21 = 42.52). There are a few other revenue items—specifically, transmission revenue, sales for resale, and rent—which is combined with this to arrive at 41.81 total average revenue lag.

Q. **HOW ARE THE AVERAGE EXPENSE LAG PERIODS CALCULATED?**

A. The average expense lag periods were determined from individual analyses of each major operating expense component. For some expense components, APS' payment patterns for suppliers were identified by examination of all invoices for purchases made during a representative period. The lag periods found for each supplier were weighted to produce an average lag in the payment for that expense component. The payroll expense component lag (18.45 days), for example, was based on APS' payroll periods (employees are paid semi-monthly) and the additional time from the end of the payroll period until employees and withheld amounts were paid.

Q. PLEASE EXPLAIN WHY YOU HAVE ASSIGNED ZERO LAG DAYS TO VARIOUS EXPENSE COMPONENTS IN CALCULATING A CASH WORKING CAPITAL REQUIREMENT?

A. Certain expense items represent the consumption of capital assets that required prior commitments of cash resources (amortization of nuclear fuel, depreciation and amortization of utility property, amortization of a prepayment), which are shown as rate base components, rather than requiring the current expenditure of additional cash. Certain other expense items represent the creation of a non-cash regulatory asset (Palo Verde cost deferrals) or a liability (deferred income taxes) whose accumulated balances are being shown as individual rate base components and which do not require an additional current cash expenditure. For these items, sometimes referred to as "non-cash" expenses, I have assigned zero lag days to both revenue and expense so that no separate cash working capital requirement for these items would be calculated. Some of these items are, however, included as a separate line item on my Attachment LLR-2. This is necessary for APS to match rate base value to investor supplied capital. For example, accumulated depreciation is a rate base component which represents the amount of all depreciation expense that has been charged to customers as a cost of service/revenue requirement item up to and including the current service period. It reduces gross plant in rate base to arrive at net plant in service. However, because customers don't pay instantly at the time of using service for the depreciation components of their bill, it is necessary to reflect the amount billed to customers for depreciation expense that remained unpaid by customers at the end of the period. This non-rate base element of accumulated depreciation is calculated by multiplying the item's daily cost of service amount by the average number of days cost of service was not yet paid by customers at the end of 2002 (revenue lag).

V. DEPRECIATION & AMORTIZATION

Q. WHAT IS DEPRECIATION?

A. Depreciation is the loss in service value (that is not restored by current maintenance) that is incurred in connection with the consumption or prospective retirement of plant in the course of service. Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage value, over a period of time by allocating annual amounts to expenses. Each annual amount of depreciation accrual is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an asset renders service—in other words, the asset's useful life. The most prevalent method of allocating depreciation is to distribute an equal amount of cost to each year of service life of an asset. This method is known as straight-line depreciation.

Q. DID APS PREPARE A DEPRECIATION STUDY?

A. Yes. The Depreciation Study is attached as Attachment LLR-4 to my testimony.

Q. WHAT WAS THE PURPOSE OF THE DEPRECIATION STUDY?

A. The purpose of the depreciation study was to determine the annual depreciation accrual rates applicable to electric plant in service, including the Pinnacle West

Energy assets for which APS is seeking rate base treatment, to support APS' request to change depreciation rates pursuant to A.A.C. R14-2-102.

Q. WHO PREPARED THE DEPRECIATION STUDY?

A. APS retained the Valuation and Rate Division of Gannett Fleming, Inc., of Harrisburg, Pennsylvania to conduct the depreciation study for APS. Gannett Fleming is an engineering and consulting firm with over 1,900 employees in 50 offices throughout the United States and Canada. It has very extensive experience in conducting valuation and depreciation studies, as well as other utility related studies.

Q. WHAT WAS THE SOURCE OF DATA FOR THE DEPRECIATION STUDY?

A. The source of the data analyzed by Gannett Fleming were the property records of APS, and the property records of PWEC regarding the PWEC assets for which APS is seeking rate base treatment. The data included plant additions, retirements, transfers and adjustments through December 31, 2002. Gannett Fleming analyzed such data for historical indications of service life and net salvage; conducted on-site inspections; interviewed management for input related to its outlook for the property; and reached conclusions on the future survivor and net salvage characteristics of APS property based on the analyses, reviews, outlook of management, and consideration of the estimates used for other electric utilities.

Q. WHAT DEPRECIATION SYSTEM DOES APS PROPOSE TO USE?

A. APS proposes to continue using the straight line remaining life method of depreciation with the average service life procedure that was used in APS' 1995 depreciation study and accepted by the Commission. The straight line remaining life method is also widely used by utilities in the United States.

Q. DOES APS USE A MODIFIED STRAIGHT LINE REMAINING LIFE METHOD FOR DEPRECIABLE PROPERTY BY UTILIZING COMPOSITE OR GROUP DEPRECIATION?

A. Yes, also consistent with the 1995 study, APS continues to use a modified straight-line method which calculates depreciation based on composites and groups. A group consists of similar assets, while a composite is made up of dissimilar assets. This method averages the service lives of a number of assets using a weighted-average of the units and depreciates the group or composite as if it were a single unit. Under this methodology, capital additions are added to plant in service and capital retirements are recorded as a reduction to plant in service and accumulated depreciation. This eliminates the income statement impact of retiring plant, whether under- or over-depreciated. Net salvage, the net amount of salvage and removal, is debited or credited to accumulated depreciation as appropriate.

Q. WHY DOES APS USE COMPOSITE AND GROUP DEPRECIATION?

A. The advantage of these methods to a regulated utility is that the gains and losses of retirements and the net salvage do not directly impact the expenses of the company, thereby providing a more stable level of depreciation expense (and hence earnings) which is more reflective of the generally long lives of utility assets. Through statistical analysis, the depreciation accrual expense can be adjusted periodically, as APS is requesting in this case, to fully depreciate plant in service over the average life of the group and composite components.

Q. WHAT DEPRECIATION SYSTEM DOES APS PROPOSE TO USE FOR GENERAL PLANT ACCOUNTS?

A. APS is proposing to use the straight line remaining life method of amortization, as opposed to depreciation, for the following General Plant accounts: FERC account 391 (office furniture, computer hardware, and office equipment); FERC account 393 (stores equipment); FERC account 394 (tools, shop and garage equipment); FERC account 395 (laboratory equipment); and FERC account 398 (miscellaneous equipment).

Q. WHAT IS AMORTIZATION?

A. Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period. The period of amortization is usually either the life of the asset or liability to which it applies, or the period during which it is anticipated that the benefit will be realized.

Q. WHEN DOES APS USE AMORTIZATION?

A. In some cases, amortization is generally simpler and more straightforward than depreciation and applies to a very small portion of utility plant. Historically, APS has amortized intangibles and certain other assets when the terms of existence of the assets are readily defined or estimated due to limitation by law, regulation, contract or other economic factors.

Q. WHY SHOULD AMORTIZATION ALSO BE USED FOR THE GENERAL PLANT ACCOUNTS YOU IDENTIFIED?

A. The primary reason for the amortization of these accounts is that the cost and effort required to unitize additions as well as periodically inventory equipment and determine amounts to be retired, is disproportionate to the original cost of the equipment when compared to other electric plant accounts. The original cost in these accounts represents only about 1.0 percent of depreciable original plant.

Q. OTHER THAN FOR GENERAL PLANT, WHAT AMORTIZATION RATES IS APS REQUESTING?

A. APS is requesting that the amortization rates now in effect for assets that are currently amortized be continued. See Attachment LLR-5 for a summary of assets subject to amortization rates and the projected annual amortization expense.

Q. WOULD YOU PLEASE EXPLAIN SFR SCHEDULE C-2, LINE 7, COLUMN 19?

A. This line presents the details of the pro forma adjustments that were made to actual 2002 depreciation and amortization expense. APS' total annual depreciation and amortization increased from $284,660,000 to $287,687,000—an increase of $3,027,000. The adjustments include: (1) 2002 accrual rates as determined by the depreciation study applied to December 31, 2002 plant balances; and (2) the impact of the change from depreciation to amortization for certain general plant accounts.

Q. ARE YOU REQUESTING SPECIFIC ACTION TO BE TAKEN BY THE COMMISSION REGARDING DEPRECIATION AND AMORTIZATION?

A. Yes. APS is requesting the Commission approve the new depreciation rates as presented in the depreciation study including, for the reasons discussed above, the change in certain General Plant assets from depreciation to amortization; and the continuance of the application of amortization rates currently in effect.

VI. STATEMENT OF FINANCIAL ACCOUNTING STANDARDS NO. 143

Q. PLEASE EXPLAIN STATEMENT OF FINANCIAL ACCOUNTING STANDARDS 143 REGARDING ASSET RETIREMENT OBLIGATIONS ("ARO").

A. On January 1, 2003, APS adopted SFAS 143 as required by the Financial Accounting Standards Board ("FASB"). The standard requires the fair value of an asset retirement obligation to be recorded as a liability, along with an offsetting plant asset, when the obligation is incurred. Accretion (or increase) of the liability due to the passage of time will be recorded as an operating expense, and the capitalized cost will be depreciated over the useful life of the long-lived asset.

Q. DOES SFAS 143 APPLY TO REGULATED UTILITIES?

A. Yes. SFAS 143 applies to rate-regulated entities that meet the criteria for application of FASB Statement No. 71, Accounting for the Effects of Certain Types of Regulation, as provided in paragraph number 5 of that statement. Paragraphs 9 and 11 of SFAS 71 provide specific conditions that must be met to recognize a regulatory asset and a regulatory liability, respectively.

Q. WHAT ASSETS HAVE AN ASSET RETIREMENT OBLIGATION?

A. The Palo Verde, including the Palo Verde sale leaseback, Four Corners, Navajo, and Childs Irving generating plants have asset retirement obligations generally related to final plant decommissioning or removal costs based on regulatory or contractual requirements that have been estimated and recorded at January 1, 2003. Portions of the transmission and distribution system are located on federal, state or reservation lands or other rights of way and easements that have various requirements for removal if the land rights were terminated. These requirements for removal of system assets are also asset retirement obligations. However, due to the perpetual life characteristics of these systems, the future timing of the asset retirement obligations cannot be determined. Therefore, an asset retirement obligation is not required to be estimated and recorded until such future time as there may be an actual obligation to remove specific portions of the transmission or distribution systems. As of January 1, 2003 there were no asset retirement obligations recorded for transmission or distribution assets.

Q. **HOW IS SFAS 143 DIFFERENT FROM THE ACCOUNTING PRACTICE USED PRIOR TO JANUARY 1, 2003?**

A. Both methods recover the cost of removal over the life of the asset. The difference is in the timing of the annual expense recognition of the removal costs. The method used by APS prior to January 1, 2003, provided for the cost accumulation of removal costs in a straight-line method ratably over the life of the asset. The ARO requires the recognition of a liability when the obligation is incurred and provides for the accretion (or increase) of the liability over time with a cost accretion expense pattern that increases annually over the life of the asset.

Q. **HOW IS THE ARO LIABILITY FOR REMOVAL COST ESTIMATED UNDER SFAS 143?**

A. SFAS 143 requires the assumption that a liability is settled with a third party for an amount that would include third-party profit and market-risk premium, even if the company involved has no intention of settling the liability in this manner. The use of a third party assumption when a company intends to use internal resources would overstate costs during the life of the asset, resulting in an offsetting gain to be recognized when the asset is ultimately removed. It should be noted again that only the timing, and not the ultimate amount, of expense recognition is affected.

Q. DOES APS CURRENTLY INTEND TO REMOVE ANY ASSETS WITH AN ARO USING INTERNAL COMPANY RESOURCES FOR ALL OR PART OF THE WORK?

A. Yes, the assumption made in the nuclear decommissioning cost study was that internal company resources would be used for portions of the Palo Verde decommissioning work. By deferring the impacts of SFAS 143, the annual costs of decommissioning will not be overstated for third-party profit and market-risk premium over the life of the asset with the offsetting gain recognized in the year that decommissioning is completed.

Q. HOW WILL APS RECORD REMOVAL COSTS FOR ASSETS THAT DO NOT HAVE AN ASSET RETIREMENT OBLIGATION?

A. The cost of removal will continue to be included in the calculation of the depreciation accrual and accumulated depreciation in the same manner as it was prior to January 1, 2003, consistent with current rate making treatment.

Q. WHAT ACTION REGARDING SFAS 143 DID APS TAKE WHEN INITIALLY ADOPTING THE STANDARD ON JANUARY 1, 2003?

A. On January 1, 2003 APS recorded a liability of $219 million for its asset retirement obligations including the accretion impacts; a $67 million increase in the book value of the associated assets; and a net reduction of $192 million in accumulated depreciation related primarily to the reversal of previously recorded accumulated decommissioning and other removal costs related to these obligations. Additionally, APS recorded a regulatory liability of $40 million for its asset retirement obligations. This regulatory liability represents the cumulative timing differences between the amounts previously recovered in regulated rates in excess of the amount calculated under SFAS 143. The purpose for these actions was to make implementation of the new standard revenue neutral, so that the timing differences in the accounting would not increase or decrease APS' overall revenue requirement.

VII. COMMISSION ACTION REQUESTED

Q. IS APS REQUESTING ANY SPECIFIC COMMISSION ACTION REGARDING SFAS 143?

A. Yes, APS requests the following language be included in the decision issued in this proceeding: "The Commission approves APS' request that the application of SFAS 143 be revenue neutral in the rate making process and authorizes APS to place all impacts to its income statement caused by the adoption of SFAS 143 in regulatory accounts. Those impacts include the cumulative adjustment as of January 1, 2003 and ongoing expense recognition impacts. The Commission also approves APS' request that removal costs for assets that do not have an asset retirement obligation continue to be reflected in the depreciation accrual and accumulated depreciation."

Q. IS APS REQUESTING ANY SPECIFIC COMMISSION ACTION REGARDING DEPRECIATION?

A. Yes, APS is requesting that the Commission authorize APS to (1) implement the depreciation rates as determined by the depreciation study; (2) change from depreciation to amortization for the general plant accounts that I identified earlier; and (3) continue the application of amortization rates that are currently in effect.

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

1366090.1

Appendix A
Statement of Qualifications
Laura L. Rockenberger

Laura L. Rockenberger is the Manager of Operations Accounting in the Shared Services Finance organization for Arizona Public Service Company ("APS"). In this position, Ms. Rockenberger has responsibility for Generation and Energy Delivery Operations & Maintenance and Fuel accounting; Asset Accounting; Accounting Services Administration, including payroll and accounts payable; and Accounting Systems. These accounting services are provided to all of the Pinnacle West Capital Corporation entities.

Ms. Rockenberger graduated cum laude from Miami University in 1982 with a Bachelor of Science Degree in Business with an emphasis in Accounting and is a member of Beta Gamma Sigma. Ms. Rockenberger also has a Bachelor of Arts with an emphasis in Music, graduating cum laude from the University of South Carolina, and is a member of Phi Beta Kappa. Ms. Rockenberger has been a Certified Public Accountant in Arizona since 1985 and is a member of the Arizona Society of Certified Public Accountants and the American Institute of Certified Public Accountants.

Ms. Rockenberger was employed in public accounting by Price Waterhouse from 1982 to 1984. She joined APS in 1985 as an Internal Auditor and held positions at the Palo Verde Nuclear Generating Station and Pinnacle West Capital Corporation. In 1987 Ms. Rockenberger joined SunCor Development Company ("SunCor"), a real estate subsidiary of Pinnacle West Capital Corporation. At SunCor, she held positions as the Director of Finance and Controller. In 1998 she joined APS as the Manager of Operations Accounting, her current position.

1368569.1

Attachment LLR-1

ARIZONA PUBLIC SERVICE COMPANY
RCN by Major Plant Accounts
With Contribution In Aid of Construction Identified by Function
Test year Ended 12/31/02
(Thousands of Dollars)

Line No.	Description	Gross Amount	Contributions In Aid Of Construction	Net Amount	Line No.
1.	Intangible Plant	$ 202,508	$ -	$ 202,508	1.
2.	Production Plant	6,785,351	(50,779)	6,734,572	2.
3.	Transmission Plant	2,174,259	(76,925)	2,097,334	3.
4.	Distribution Plant	4,139,487	(124,567)	4,014,920	4.
5.	General Plant	555,785	(8,193)	547,592	5.
6.	Utility Plant In Service	$ 13,857,390	$ (260,464)	$ 13,596,926	6.

ARIZONA PUBLIC SERVICE COMPANY
Cash Working Capital Summary - Lead Lag Study
Twelve Months Ended December 31, 2002

Line No.	Description	Working Capital Requirement (Source)	Line No.
1.	Cash Required For (Provided By) Operating Expenses	(20,969,724)	1.
2.	Non Rate-Based Elements of Rate-Based Components	74,809,380	2.
3.	Special Deposits and Working Funds	258,266	3.
4.	Net Cash Working Capital Required For (Provided By) Operations	54,097,922	4.

ARIZONA PUBLIC SERVICE COMPANY
Cash Working Capital Required for Operating Expenses - Lead Lag Study
Twelve Months Ended December 31, 2002

Line No.	Description	Amount	Revenue Lag Days	Expense Lag Days	Net Lag Days	CWC * Factor	Working Capital Requirement	Line No.
		(1)	(2)	(3)	(4)	(5)	(6)	
1.	Fuel for Electric Generation							1.
2.	Coal	157,018,541	41.81069	30.86168	10.94901	0.03000	4,710,556	2.
3.	Natural Gas	75,641,831	41.81069	41.62912	0.18156	0.00050	37,821	3.
4.	Fuel Oil	1,220,091	41.81069	27.40279	14.40790	0.03947	48,157	4.
5.	Nuclear:							5.
6.	Amortization	31,251,461	0.00000	0.00000	0.00000	0.00000	0	6.
7.	Spent Fuel	8,296,700	41.81069	76.37500	-34.56431	-0.09470	(785,697)	7.
8.	Total	273,428,624					4,010,837	8.
9.								9.
10.	Purchased Power	343,858,302	41.81069	37.83806	3.97263	0.01088	3,741,178	10.
11.	Transmission by Others	10,742,660	41.81069	34.02490	7.78579	0.02133	229,141	11.
12.	Total	354,600,962					3,970,319	12.
13.								13.
14.	Other Operations & Maintenance:							14.
15.	Payroll	213,167,640	41.81069	18.44744	23.36325	0.06401	13,644,861	15.
16.	Severance	28,223,377	0.00000	0.00000	0.00000	0.00000	0	16.
17.	Pension and OPEB	19,989,248	0.00000	0.00000	0.00000	0.00000	0	17.
18.	Employee Benefits	16,752,698	41.81069	17.02000	24.79069	0.06792	1,137,843	18.
19.	Payroll Taxes	13,328,087	41.81069	13.98000	27.83069	0.07625	1,016,267	19.
20.	Materials & Supplies	40,910,931	41.81069	29.34000	12.47069	0.03417	1,397,927	20.
21.	Franchise Payments	28,932,439	41.81069	68.19607	-26.38538	-0.07229	(2,091,526)	21.
22.	Vehicle Lease Payments	7,228,287	41.81069	38.09947	3.71122	0.01017	73,512	22.
23.	Rents	4,962,688	41.81069	-31.71012	73.52081	0.20143	999,634	23.
24.	Palo Verde Lease	45,202,210	41.81069	53.29167	-11.48098	-0.03145	(1,421,610)	24.
25.	Palo Verde S/L Gain Amort	(4,575,722)	0.00000	0.00000	0.00000	0.00000	0	25.
26.	Insurance	2,430,999	0.00000	0.00000	0.00000	0.00000	0	26.
27.	Uncollectible Accounts	2,680,484	0.00000	0.00000	0.00000	0.00000	0	27.
28.	Other	76,612,102	41.81069	37.55000	4.26069	0.01167	894,063	28.
29.	Total	495,845,469					15,650,971	29.
30.								30.
31.	Depreciation & Amortization	284,659,929	0.00000	0.00000	0.00000	0.00000	0	31.
32.	Amort of Elelctric Plt Acq Adj	15,443,124	0.00000	0.00000	0.00000	0.00000	0	32.
33.	Amort of Prop Losses & Reg Study Costs	99,536,541	0.00000	0.00000	0.00000	0.00000	0	33.
34.	Total	399,639,594					0	34.
35.								35.
36.	Income Taxes:							36.
37.	Current:							37.
38.	Federal	(61,961,636)	41.81069	60.05000	-18.23931	-0.04997	3,096,223	38.
39.	State	(17,998,536)	41.81069	62.34755	-20.53686	-0.05627	1,012,778	39.
40.	Deferred	206,767,266	0.00000	0.00000	0.00000	0.00000	0	40.
41.	Total	126,807,094					4,109,001	41.
42.								42.
43.	Other Taxes:							43.
44.	Property Taxes	103,969,716	41.81069	212.81731	-171.00662	-0.46851	(48,710,852)	44.
45.	Sales Taxes	3,955,025	0.00000	0.00000	0.00000	0.00000	0	45.
46.	Total	107,924,741					(48,710,852)	46.
47.								47.
48.	Total	1,758,246,484					(20,969,724)	48.

* CWC is rounded to 5 digits.

Attachment LLR-4

ARIZONA PUBLIC SERVICE COMPANY

PHOENIX, ARIZONA

DEPRECIATION STUDY

RECOMMENDED REMAINING LIFE DEPRECIATION ACCRUAL RATES AS OF DECEMBER 31, 2002

Gannett Fleming
Valuation and Rate Division

Harrisburg, Pennsylvania   Calgary, Alberta   Valley Forge, Pennsylvania

ARIZONA PUBLIC SERVICE COMPANY

Phoenix, Arizona

DEPRECIATION STUDY

RECOMMENDED REMAINING LIFE DEPRECIATION ACCRUAL RATES

AS OF DECEMBER 31, 2002

GANNETT FLEMING, INC. - VALUATION AND RATE DIVISION

Harrisburg, Pennsylvania Calgary, Alberta Valley Forge, Pennsylvania

Gannett Fleming

GANNETT FLEMING, INC.
P.O. Box 80794
Valley Forge, PA 19484-0794
Location:
Valley Forge Corporate Center
1010 Adams Avenue
Audubon, PA 19403-2402
Office: (610) 650-8101
Fax: (610) 650-8190
www.gannettfleming.com

June 12, 2003

Arizona Public Service Company
400 North 5th Street
Phoenix, AZ 85006

Attention Mr. Chris Froggatt
Vice President and Controller

Ladies and Gentlemen:

Pursuant to your request, we have studied the service life and net salvage characteristics of the electric plant of the Arizona Public Service Company for the purpose of determining recommended annual depreciation accrual rates as of December 31, 2002. The results of our study are presented in the attached report.

The report sets forth a description of the concepts and methods upon which the study was based, our estimates of survivor curves and net salvage, and the ensuing remaining life depreciation accrual rates. The results of the study are summarized in the table on pages III-4 through III-7.

Respectfully submitted,

GANNETT FLEMING, INC.

John F. Wiedmayer

JOHN F. WIEDMAYER, CDP
Supervisor, Depreciation Studies
Valuation and Rate Division

JFW:krm

CONTENTS

PART I. INTRODUCTION

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

PART III. RESULTS OF STUDY

1 # PART I. INTRODUCTION

ARIZONA PUBLIC SERVICE COMPANY

DEPRECIATION STUDY

PART I. INTRODUCTION

PLAN OF THE REPORT

This report presents the methods used in and the results of the depreciation study conducted for Arizona Public Service Company (APS or the Company). Part I, Introduction, contains statements with respect to the basis of the depreciation study. Part II, Methods Used in the Estimation of Depreciation, presents the methods and procedures used to analyze historical data and the procedures used to calculate annual and accrued depreciation. Part III, Results of Study, contains a summary tabulation of the annual and accrued depreciation calculations. The statistical support for the estimates of service life and net salvage, and the detailed calculations of the annual and accrued depreciation are set forth in the Appendices of the report.

BASIS OF THE STUDY

The purpose of the study was to determine the annual remaining life depreciation accrual rates applicable to electric plant in service as of December 31, 2002. For most accounts, the annual and accrued depreciation were calculated by the straight line method, remaining life basis, and the average service life procedure. For certain General Plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and estimates of survivor curves and net salvage percents for each account as of December 31, 2002.

The change to amortization accounting for certain general plant accounts is recommended because of the disproportionate accounting effort required when compared to the minimal original cost of the large number of items in these accounts. Many electric utilities in North America have received approval to adopt amortization accounting for these accounts. An explanation of the calculation of the annual and accrued amortization is presented beginning on page II-35 of the report.

The service life and net salvage estimates used in the depreciation and amortization calculations were based on judgment which incorporated analyses of available historical data, a review of current policies and outlook with management, a field survey of the property, a general knowledge of the electric industry, and comparisons of the survivor curve and net salvage estimates from studies of other electric companies. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for utility property. Iowa type survivor curves were used to depict the estimated survivor curves for most of the property groups. For the power plant structures and equipment in Accounts 311 through 346, probable retirement years were estimated and the life span procedure of calculating depreciation was used to provide for the simultaneous retirement of all associated property, surviving from various years of installation, at the time of the retirement of the major investment. The estimates of net salvage are expressed as the average net salvage percent of the investment to be incurred or recovered upon it retirement.

PART II. METHODS USED

IN THE ESTIMATION OF DEPRECIATION

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

DEPRECIATION

Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption of prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authority.

Depreciation as used in accounting is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight line method of depreciation.

The calculation of annual depreciation based on the straight line method requires the estimation of average life and salvage. These subjects are discussed in the sections which follow.

SERVICE LIFE AND NET SALVAGE ESTIMATION

Average Service Life

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages. A discussion of the general concept of survivor curves is presented. Also, the Iowa type survivor curves are reviewed.

Survivor Curves

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1 a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1 the remaining life at age 30 years is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval and is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

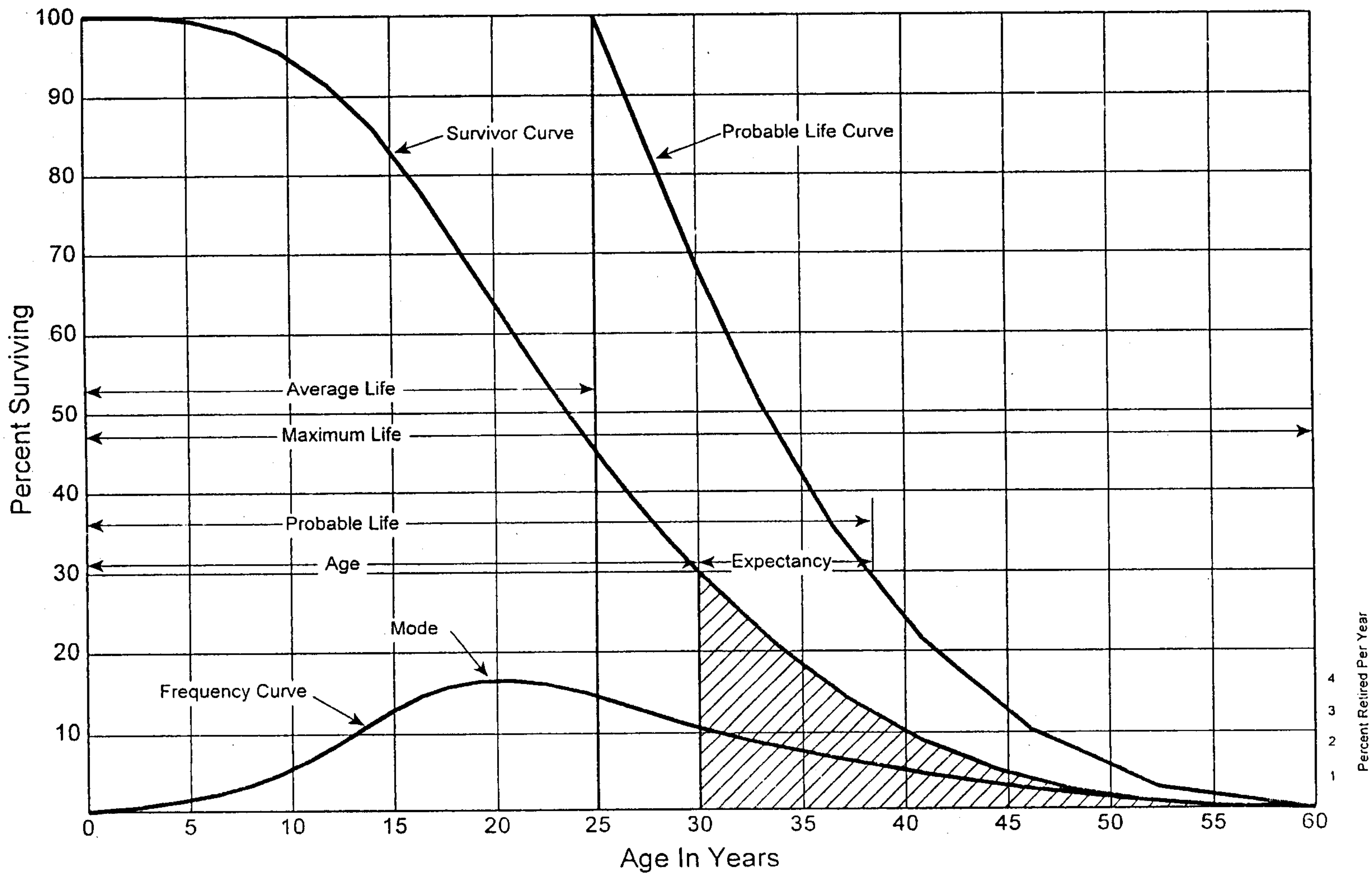

Figure 1. A Typical Survivor Curve and Derived Curves

Iowa Type Curves. The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency of retirement occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numerical subscripts represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitutes three of the four families, was published in 1935 in the form of the Experiment

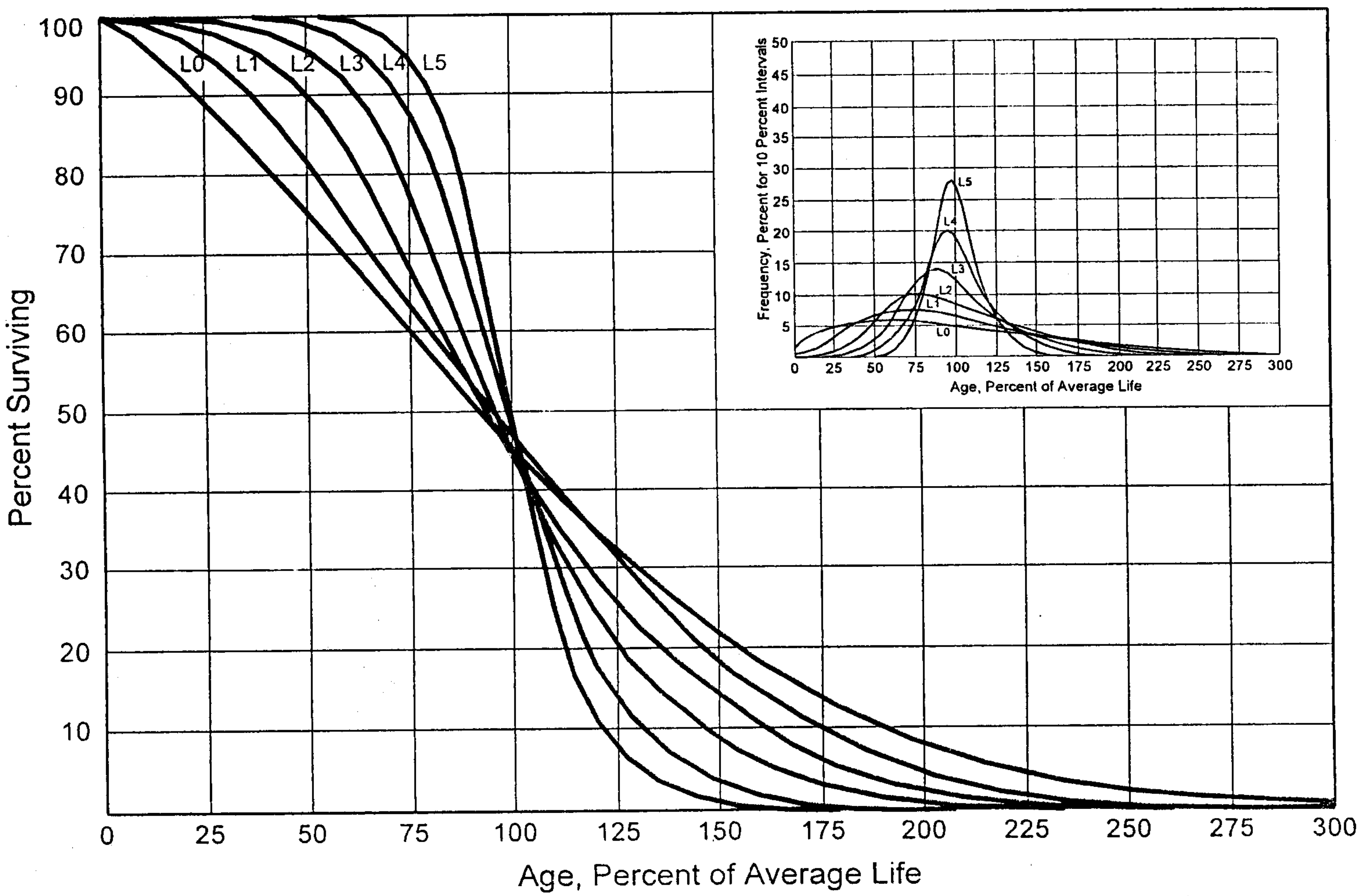

Figure 2. Left Modal or "L" Iowa Type Survivor Curves

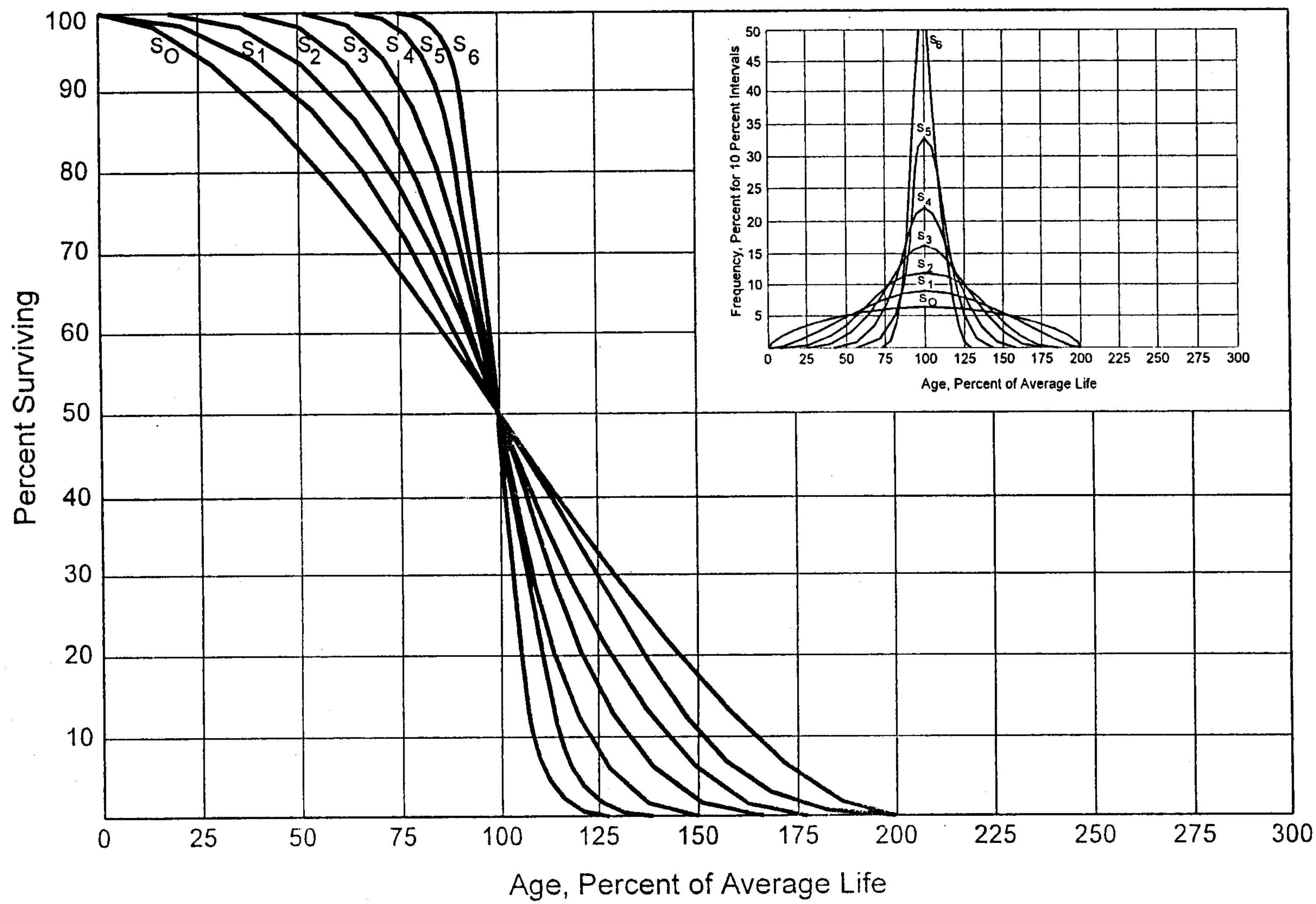

Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

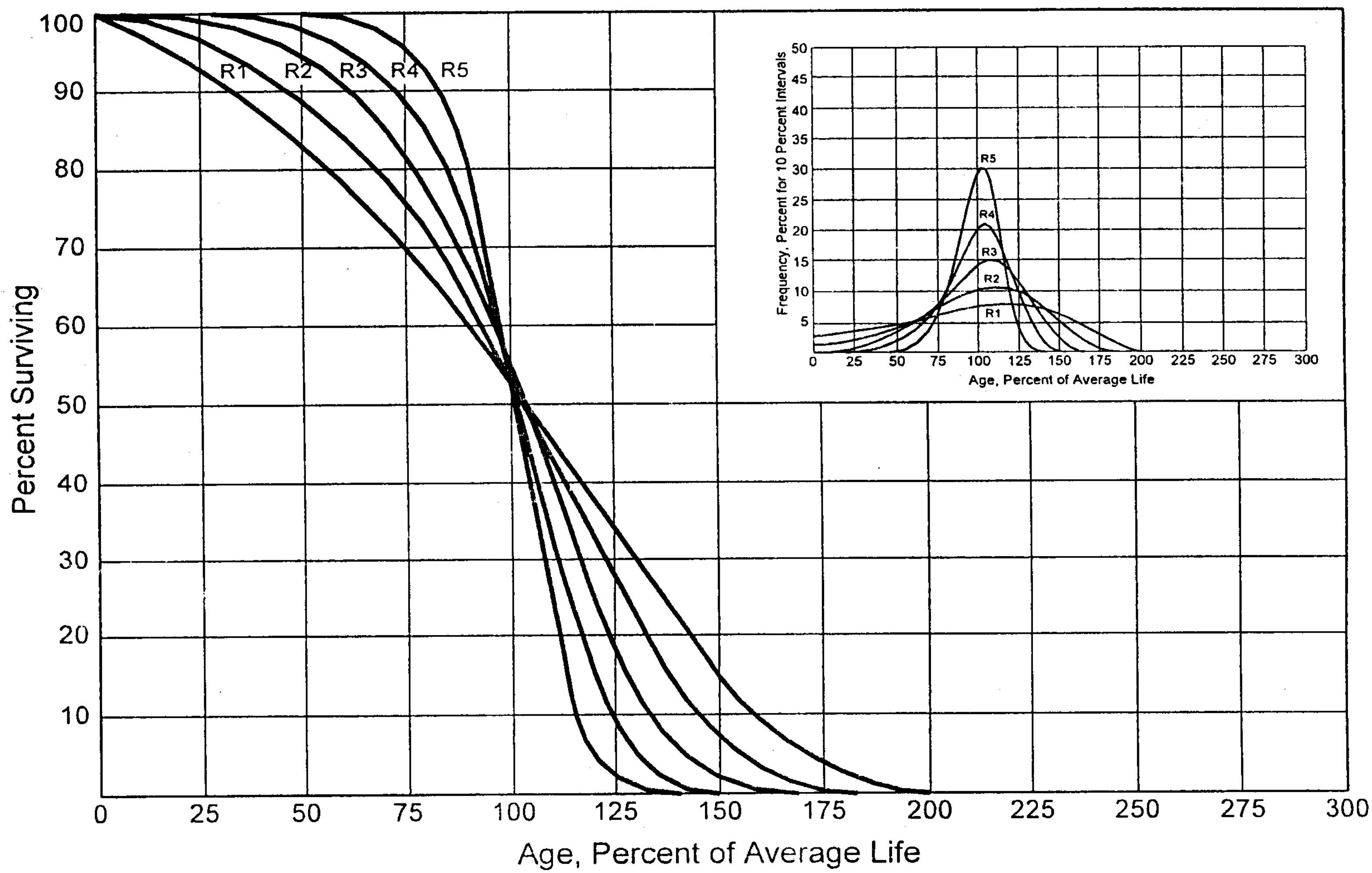

Figure 4. Right Modal or "R" Iowa Type Survivor Curves

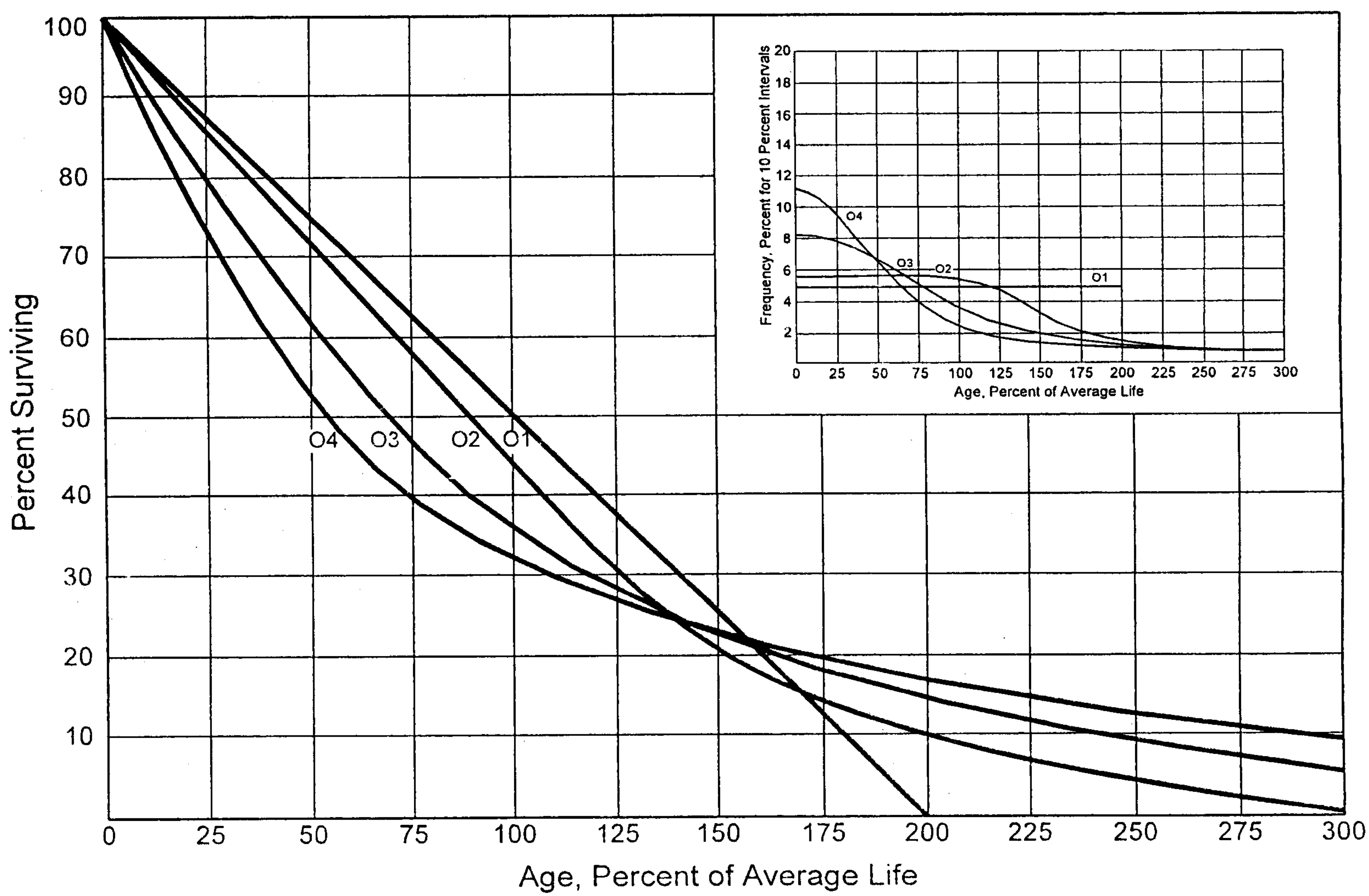

Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

Station's Bulletin 125.[1] These type curves have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[2] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[3] presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available or for which aged accounting experience is developed by statistically aging unaged amounts and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[4] "Engineering Valuation and Depreciation,"[5] and "Depreciation Systems."[6]

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[1]Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[2]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[3]Couch, Frank V. B., Jr. "Classification of Type O Retirement Characteristics of Industrial Property." Unpublished M.S. thesis (Engineering Valuation). Library, Iowa State College, Ames, Iowa. 1957.

[4]Winfrey, Robley, Supra Note 1.

[5]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 2.

[6]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows on pages II-12 and II-13. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table, and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records. The property group used to illustrate the retirement rate method is observed for the experience band 1992-2001 during which there were placements during the years 1987-2001. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Tables 1 and 2 on pages II-12 and II-13. In Table 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, \$10,000 of the dollars invested in 1987 were retired in 1992. The \$10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as

TABLE 1. RETIREMENTS FOR EACH YEAR 1992-2001
SUMMARIZED BY AGE INTERVAL

Experience Band 1992-2001

Placement Band 1987-2001

Year Placed (1)	1992 (2)	1993 (3)	1994 (4)	1995 (5)	1996 (6)	1997 (7)	1998 (8)	1999 (9)	2000 (10)	2001 (11)	Total During Age Interval (12)	Age Interval (13)
	Retirements, Thousands of Dollars During Year											
1987	10	11	12	13	14	16	23	24	25	26	26	13½-14½
1988	11	12	13	15	16	18	20	21	22	19	44	12½-13½
1989	11	12	13	14	16	17	19	21	22	18	64	11½-12½
1990	8	9	10	11	11	13	14	15	16	17	83	10½-11½
1991	9	10	11	12	13	14	16	17	19	20	93	9½-10½
1992	4	9	10	11	12	13	14	15	16	20	105	8½-9½
1993		5	11	12	13	14	15	16	18	20	113	7½-8½
1994			6	12	13	15	16	17	19	19	124	6½-7½
1995				6	13	15	16	17	19	19	131	5½-6½
1996					7	14	16	17	19	20	143	4½-5½
1997						8	18	20	22	23	146	3½-4½
1998							9	20	22	25	150	2½-3½
1999								11	23	25	151	1½-2½
2000									11	24	153	½-1½
2001	—	—	—	—	—	—	—	—	—	13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

TABLE 2. OTHER TRANSACTIONS FOR EACH YEAR 1992-2001
SUMMARIZED BY AGE INTERVAL

Experience Band 1992-2001

Placement Band 1987-2001

Year Placed (1)	1992 (2)	1993 (3)	1994 (4)	1995 (5)	1996 (6)	1997 (7)	1998 (8)	1999 (9)	2000 (10)	2001 (11)	Total During Age Interval (12)	Age Interval (13)
	Acquisitions, Transfers, and Sales, Thousands of Dollars											
			During Year									
1987	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
1988	-	-	-	-	-	-	-	-	-	-	-	12½-13½
1989	-	-	-	-	-	-	-	-	-	-	-	11½-12½
1990	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
1991	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
1992		-	-	-	-	-	-	-	-	-	(5)	8½-9½
1993		-	-	-	-	-	-	-	-	-	6	7½-8½
1994			-	-	-	-	-	-	-	-	-	6½-7½
1995				-	-	-	-	(12)[b]	-	-	-	5½-6½
1996					-	-	-	-	22[a]	-	-	4½-5½
1997						-	-	(19)[b]	-	-	10	3½-4½
1998							-	-	-	-	-	2½-3½
1999								-	-	(102)[c]	(121)	1½-2½
2000									-	-	-	½-1½
2001											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use

Parentheses denote Credit amount.

occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Table 1 immediately above the stairstep line drawn on the table beginning with the 1992 retirements of 1987 installations and ending with the 2001 retirements of the 1996 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

In Table 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements but are used in developing the exposures at the beginning of each age interval.

<ins>Schedule of Plant Exposed to Retirement</ins>. The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Table 3 on page II-15.

The surviving plant at the beginning of each year from 1992 through 2001 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Table 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net

TABLE 3. PLANT EXPOSED TO RETIREMENT JANUARY 1 OF EACH YEAR 1992-2001 SUMMARIZED BY AGE INTERVAL

Experience Band 1992-2001

Placement Band 1987-2001

Year Placed (1)	1992 (2)	1993 (3)	1994 (4)	1995 (5)	1996 (6)	1997 (7)	1998 (8)	1999 (9)	2000 (10)	2001 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
	Exposures, Thousands of Dollars: Annual Survivors at the Beginning of the Year											
1987	255	245	234	222	209	195	239	216	192	167	167	13½-14½
1988	279	268	256	243	228	212	194	174	153	131	323	12½-13½
1989	307	296	284	271	257	241	224	205	184	162	531	11½-12½
1990	338	330	321	311	300	289	276	262	242	226	823	10½-11½
1991	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
1992	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
1993		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
1994			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
1995				580[a]	574	561	546	530	501	482	3,057	5½-6½
1996					660[a]	653	639	623	628	609	3,789	4½-5½
1997						750[a]	742	724	685	663	4,332	3½-4½
1998							850[a]	841	821	799	4,955	2½-3½
1999								960[a]	949	926	5,719	1½-2½
2000									1,080[a]	1,069	6,579	½-1½
2001										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a] Additions during the year.

entries shown on Tables 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 1997 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

For the entire experience band 1992-2001, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Table 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½ -5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table. The original life table, illustrated in Table 4 on page II-17, is developed from the totals shown on the schedules of retirements and exposures, Tables 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the

TABLE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 1992-2001 Placement Band 1987-2001

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval (1)	Exposures at Beginning of Age Interval (2)	Retirements During Age Interval (3)	Retirement Ratio (4)	Survivor Ratio (5)	Percent Surviving at Beginning of Age Interval (6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Table 3, Column 12, Plant Exposed to Retirement.
Column 3 from Table 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 divided by Column 2.
Column 5 = 1.0000 minus Column 4.
Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the interval by the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Tables 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

The original survivor curve is plotted from the original life table (column 6, Table 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

<u>Smoothing the Original Survivor Curve</u>. The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities as there is still an extrapolation for the vintages which have not yet lived to the age at which the

curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8 the original curve developed in Table 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6 the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7 the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8 the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0. In Figure 9 the three fittings, 12-L1, 12-S0, and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group, assuming no contrary relevant factors external to the analysis of historical data.

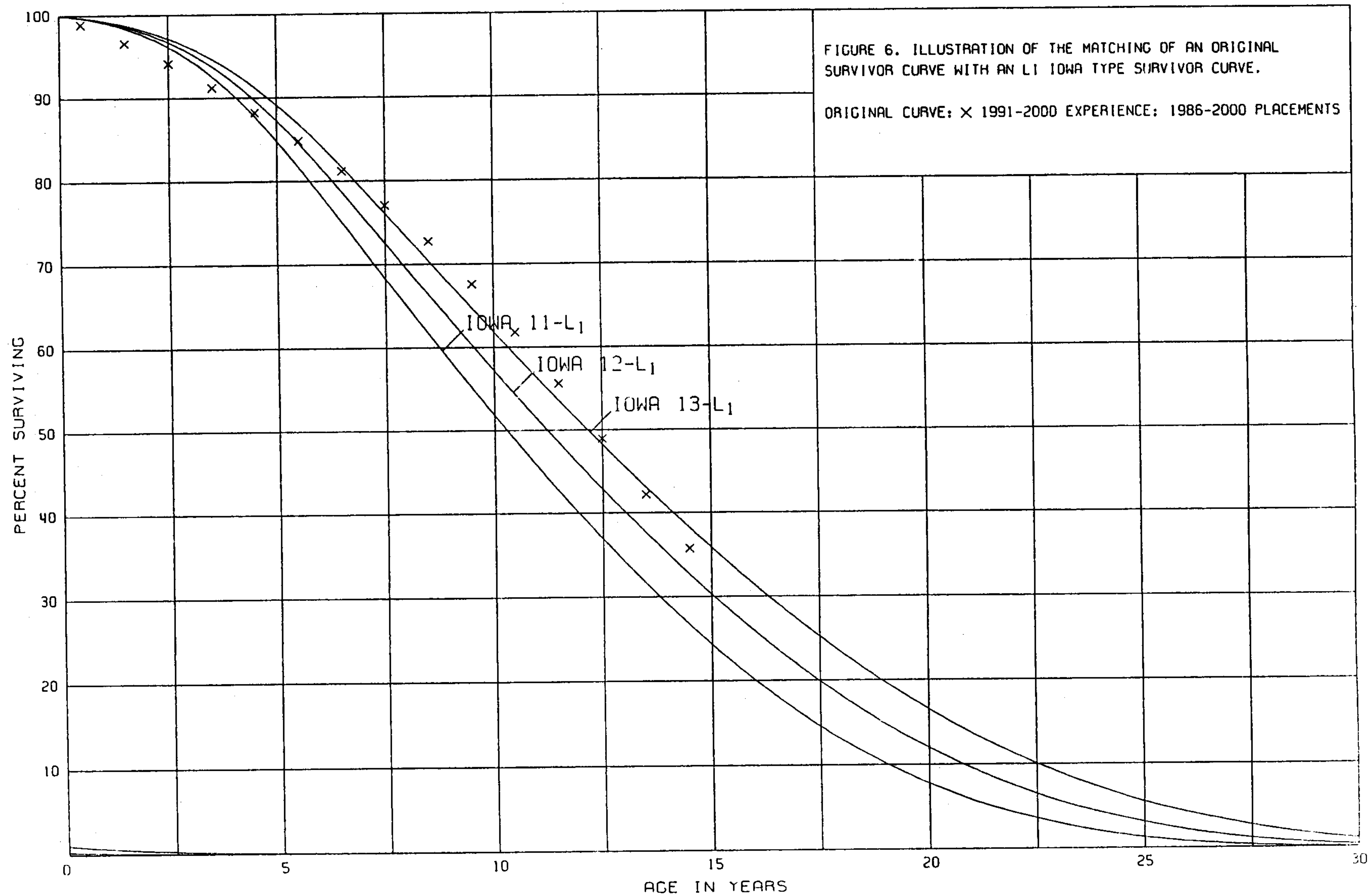


FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE SURVIVOR CURVE.
ORIGINAL CURVE: × 1991-2000 EXPERIENCE: 1986-2000 PLACEMENTS
IOWA 11-L1
IOWA 12-L1
IOWA 13-L1
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30

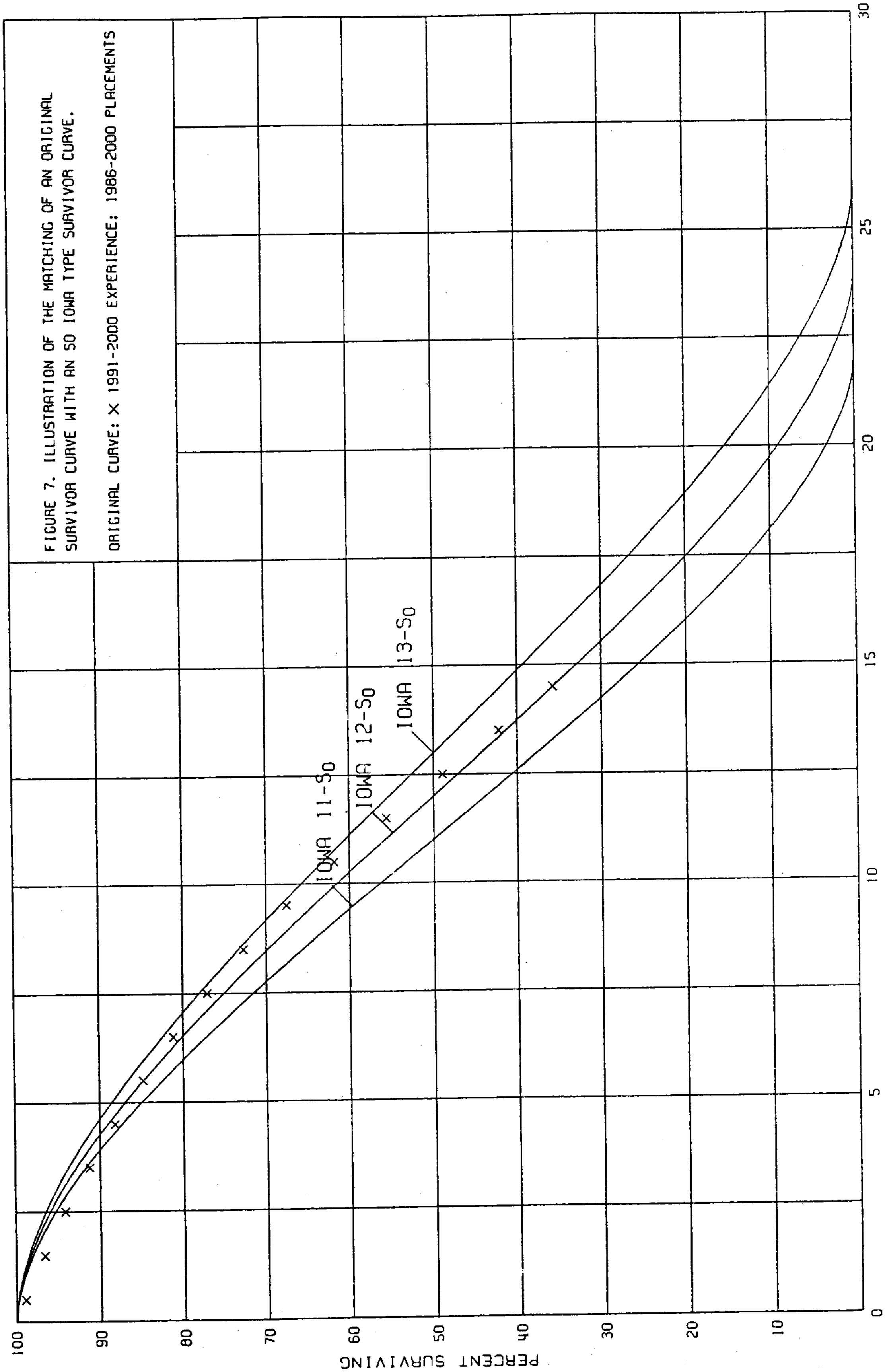


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE SURVIVOR CURVE.

ORIGINAL CURVE: X 1991-2000 EXPERIENCE; 1986-2000 PLACEMENTS

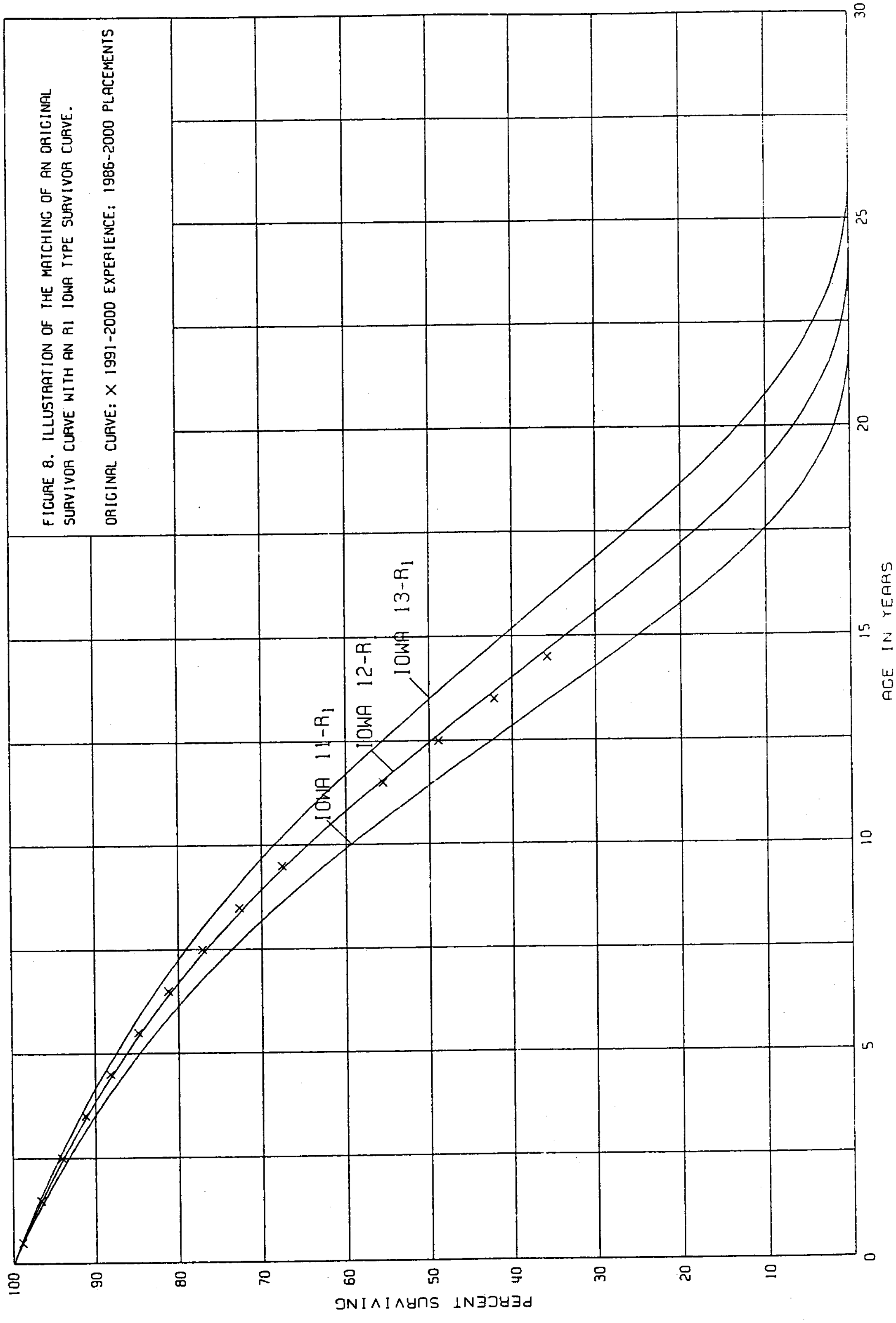


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE SURVIVOR CURVE.

ORIGINAL CURVE: × 1991-2000 EXPERIENCE; 1986-2000 PLACEMENTS

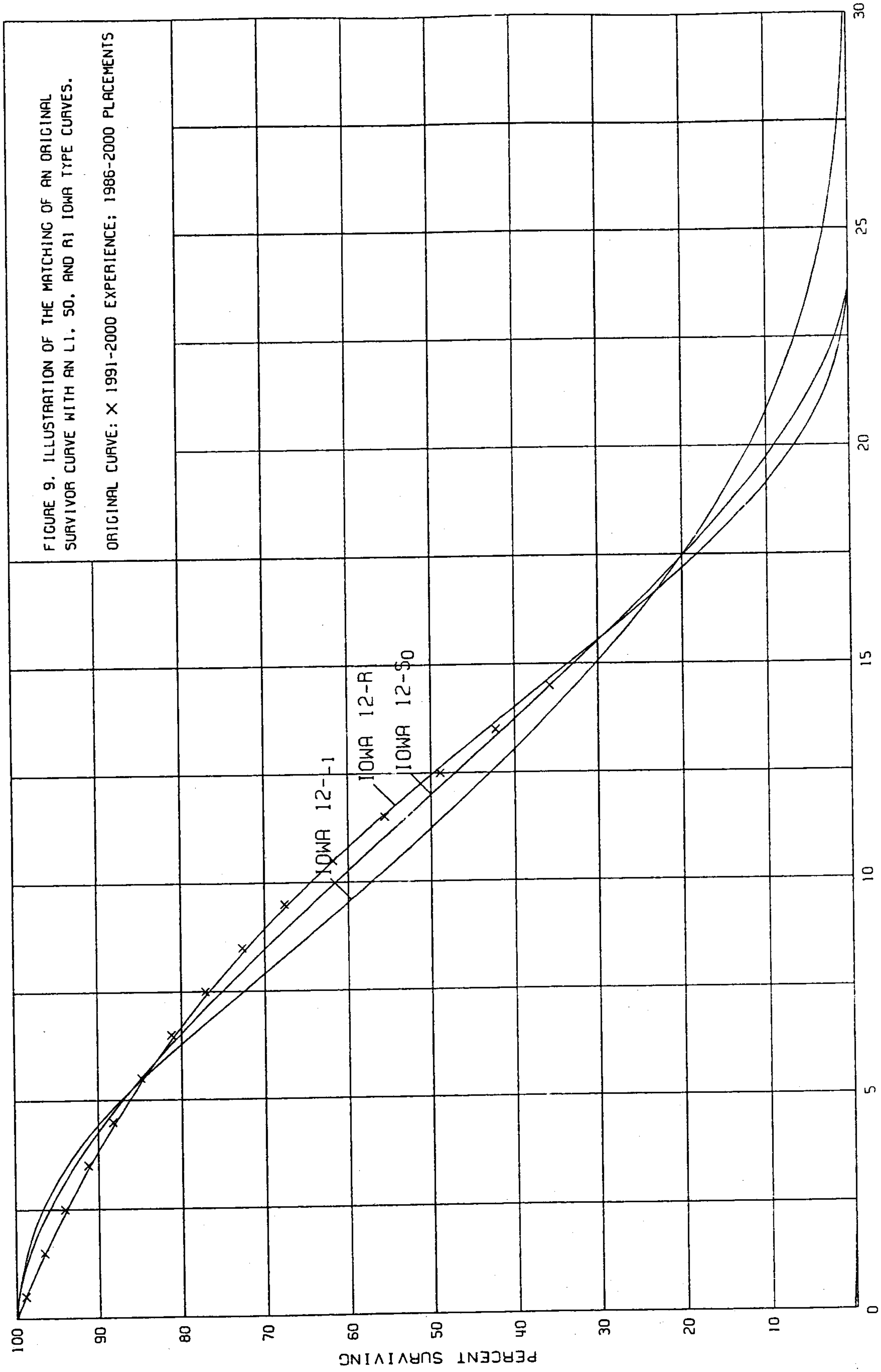


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0, AND R1 IOWA TYPE CURVES.

ORIGINAL CURVE: X 1991-2000 EXPERIENCE; 1986-2000 PLACEMENTS

Service Life Considerations

The service life estimates were based on judgment which considered a number of factors. The primary factors were the statistical analyses of data; current Company policies and outlook as determined during field reviews of the property and other conversations with management; and the survivor curve estimates from previous studies of this company and other electric companies.

For 13 of the 58 plant accounts and subaccounts, the statistical analyses resulted in good to excellent indications of complete survivor patterns. These accounts represent 41 percent of depreciable electric plant studied. Generally, the information external to the statistics led to no significant departure from the indicated survivor curves for the accounts listed below. The statistical support for the service life estimates is presented in Appendix A.

TRANSMISSION PLANT

353	Station Equipment
355	Poles and Fixtures - Wood

DISTRIBUTION PLANT

362	Station Equipment
364	Poles, Towers and Fixtures - Wood
365	Overhead Conductors and Devices
366	Underground Conduit
367	Underground Conductors and Devices
368	Line Transformers
370	Meters
371	Installations on Customers Premises
373	Street Lighting and Signal Systems

GENERAL PLANT

390	Structures and Improvements
397	Communication Equipment

Account 355, Poles and Fixtures - Wood, is used to illustrate the manner in which the study was conducted for the group of accounts in the preceding list. Aged plant accounting data have been compiled for the years 1972 through 2001. These data have been coded in the course of the Company's normal recordkeeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The retirements, other plant transactions, and plant additions were analyzed by the retirement rate method.

The survivor curve estimate is based on the statistical indication for the period 1973 through 2001. The Iowa 48-R1.5 is an excellent fit of the significant portion of the original survivor curve. The 48-year service life is at the upper end of the typical service life range of 35 to 50 years for poles and fixtures. The previous estimate was the Iowa 43-R1.

The primary causes of retirements have been inadequacy, decay and pole relocations. The poles are retired due to their inability to support heavier conductors, in addition to the degradation of the poles caused by natural sources, i.e., termites, woodpeckers and decay. These causes of retirement are expected to continue in the foreseeable future.

The production plant accounts comprise 23 of the 58 plant accounts or subaccounts and represent 47 percent of depreciable electric plant studied. Inasmuch as production plant consists of large generating units, the life span technique was employed in conjunction with the use of interim survivor curves which reflect interim retirements that occur prior to the ultimate retirement of the major unit. An interim survivor curve was estimated for each plant account, inasmuch as the rate of interim retirements differs from account to account. The interim survivor curves estimated for certain steam and nuclear production plant accounts were based on the retirement rate method of life analysis which incorporated experienced and estimated aged retirements for the period 1973 through 2010 for the steam plants and the period 1986 through 2010 for the nuclear plants. The 2002 through 2010 retirements were based on replacements incorporated in the Company's 10-year capital plan for production facilities. The statistical support for the interim rates of retirement for production plant accounts are set forth in Appendix A.

The life span estimates for power generating stations were the result of considering experienced life spans of similar generating units, the age of surviving units, general operating characteristics of the units, major refurbishing, and discussions with management personnel concerning the probable long-term outlook for the units.

The life span estimate for the coal-fired, base-load units is 55 years, which is at the upper end of the typical range of life spans for such units. The 55-year life span estimate applies to Cholla Units 1-3. The other coal-fired, base-load units are located on Navajo land, i.e., Four Corners Units 1-5, and Navajo Units 1-3, and the company has a lease agreement with the Navajo Nation to operate the plants for a specified period. A 53-year life span was estimated for Four Corners Units 1-3. The probable retirement dates for Four Corners Units 4-5 and Navajo 1-3 were set to coincide with the lease expiration dates for each respective location. The lease expiration dates for Four Corners and Navajo occur in 2031 and 2026, respectively. For the gas-fired, peak-load steam production units at Ocotillo, Saguaro, and Yucca, a 60-year life span has been estimated based on discussions with management and the favorable operating and maintenance practices that exist at these plants.

The life span for nuclear production units is based on the length of the operating license as established by the Nuclear Regulatory Commission. The Company's operating license is valid for 40 years from the date of issue. Therefore, the life spans estimated for

Palo Verde Units 1-3 are slightly less than 40 years since the units did not begin commercial operation until several months after the operating license was issued.

The life span for the steam generators at Palo Verde is based on specific replacement plans set forth by APS. The development of cracks in the steam generator tubes is the reason for the replacement of the units. Such cracking has been experienced in the steam generator tubes of other electric utilities and has resulted in the replacement of steam generators. Tubes can be plugged for a period of time, but ultimately the steam generator must be replaced. The company's replacement plans for the steam generator tubes are as follows: Unit 2 in 2003; Unit 1 in 2005; Unit 3 in 2007.

The life span estimate for the West Phoenix combined cycle units 1-3 has been extended to 2031 based on the significant refurbishment of the units that occurred in 2001 and the outlook of engineering management. In the previous study, the plant investment related to the West Phoenix combined cycle units 1-3 plant was depreciated over the term of the lease. The length of the lease was 25 years, ending in 2001. A life span of 45 years was estimated for the simple cycle combustion turbines at Douglas, Ocotillo, Saguaro, West Phoenix and Yucca. A 45-year life span estimate is at the upper end of the range typically used for such units but the 45-year life span is consistent with management's outlook.

Common plant for each steam, nuclear and other production station was life-spanned to the same date as the unit with the latest probable retirement year. A summary of the year in service, life span and probable retirement year for each power production unit follows:

Depreciable Group	Year in Service	Probable Retirement Year	Life Span
STEAM PRODUCTION PLANT			
Chollo Unit 1	1962	2017	55
Chollo Unit 2	1978	2033	55
Chollo Unit 3	1980	2035	55
Chollo Common	1978	2035	57
Four Corners Units 1-3	1963	2016	53
Four Corners Units 4-5	1969	2031	62
Navajo Units 1-3	1975	2026	51
Ocotillo Units 1-2	1960	2020	60
Saguaro Units 1-3	1954	2014	60
Yucca Unit 1	1959	2016	57
NUCLEAR PRODUCTION PLANT			
Palo Verde Unit 1	1986	2024	40
Palo Verde Unit 2	1986	2025	40
Palo Verde Unit 3	1988	2027	40
Palo Verde Water Reclamation	1986	2027	40
Palo Verde Common	1986	2027	40
HYDRAULIC PRODUCTION PLANT			
Childs	1909	2004	95
Irving	1916	2004	88
OTHER PRODUCTION PLANT			
Douglas	1972	2017	45
Ocotillo Turbines 1-2	1972	2017	45
Saguaro Turbines 1-2	1972	2017	45
West Phoenix Turbines 1-2	1972	2017	45
West Phoenix Combined Cycle 1-3	1976	2031	55
Yucca Turbines 1-4	1971	2016	45

The estimated retirement dates should not be interpreted as commitments to retire these plants on these dates, but rather, as reasonable estimates subject to modification in the future as circumstances dictate.

Amortization accounting is proposed for 7 General Plant accounts that represent numerous units of property, but a small portion of the depreciable electric plant in service. These accounts represent 1 percent of the total depreciable electric plant studied. A discussion of the basis for the amortization periods is presented in the section "Calculation of Annual and Accrued Amortization."

Generally, the survivor curve estimates for the remaining 15 accounts, which comprise 11 percent of the total depreciable original cost, were based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data, and a general knowledge of the service lives for similar equipment in other electric companies.

Salvage Analysis

The estimates of net salvage were based in part on historical data compiled for the years 1980 through 2001. Cost of removal and salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates are expressed as a percent of the original cost of plant retired.

Net Salvage Considerations

The survivor curve and net salvage estimates were based on judgment which considered a number of factors. The primary factors were the analyses of historical data; information relative to APS policies and outlook as determined during the field trip and other discussions with management; a general knowledge of the electric industry; and the service life characteristics and net salvage percents of other electric companies.

Generally, conclusions were formed separately for the cost of removal and gross salvage components of net salvage and then were consolidated into an estimate of net salvage. This procedure encourages observation of separate trends in the several components.

Many transmission and distribution plant accounts experience high levels of reuse salvage, i.e., materials returned to stores, during the early portion of a group's life cycle. Items such as transformers that become inadequate at one location can be reused at another, if they are in good condition. However, as the group ages, the ability to reuse materials decreases and ultimately ceases.

Analyses of gross salvage for accounts which experience reuse require interpretation in order to develop an estimate of gross salvage that applies to the entire life cycle. As a result of inflation, most of the original cost retired relates to relatively young plant which can be reused. Thus, the analysis of gross salvage provides an indication that only would be correct if such plant was capable of being reused throughout its life cycle.

The table on page II-32 sets forth the adjustment procedure used for certain APS transmission and distribution plant accounts which experience reuse. The adjustment process consists of estimating the age beyond which plant will not be reused, determining the percent surviving at that age and weighting the experienced gross salvage indication by 100 percent less the percent surviving, the percent retired. The resultant adjusted gross salvage better represents the level of gross salvage that will be experienced by the group during its entire life cycle.

The net salvage estimate for steam production plant reflects estimated decommissioning costs associated with each generating station. The decommissioning cost estimate for each unit was based on the results of a least-squares regression analysis of decommissioning cost data for power plants operated by other electric utilities. The regression analysis correlated the decommissioning costs experienced and estimated by other electric utilities with the size of the generating station, in megawatts (MW). The regression equation determines values for the dependent variable, i.e., decommissioning costs, at every given value for the independent variable, i.e., MW. The estimated decommissioning cost for each of the Company's generating stations was determined through the application of the regression equation to the MW values of each unit. The estimated decommissioning costs were escalated to a future price level coinciding with the year the plants are to be retired. The resultant estimated decommissioning costs were then expressed as a percent of the original cost of the plant in service as of December 31, 2002.

ARIZONA PUBLIC SERVICE COMPANY

Table A. Development of Adjusted Net Salvage Percents for Accounts Which Experience High Levels of Reuse Salvage

			Cost of Removal		Gross Salvage		Net Salvage			Adjusted Gross Salvage		Adjusted Net Salvage		Estimated Net Salvage Percent
Account	Period	Retirements	Amount	Pct	Amount	Pct	Amount	Pct	Reuse Factor	Amount	Pct	Amount	Pct	
353	'80-01	22,385,319	2,047,921	9	4,685,218	21	2,637,297	12	40	1,874,087	8	(173,834)	-1	
353	'97-01	1,321,957	200,866	15	353,895	27	153,029	12	40	141,558	11	(59,308)	-4	0
354-356	'80-01	20,137,049	11,824,572	59	13,689,830	68	1,865,258	9	30	4,106,949	20	(7,717,623)	-38	
354-356	'97-01	1,077,982	643,833	60	856,998	80	213,165	20	30	257,099	24	(386,734)	-36	-35
362	'80-01	24,590,679	3,610,820	15	12,810,742	52	9,199,922	37	40	5,124,297	21	1,513,477	6	
362	'97-01	1,551,737	274,741	18	1,483,317	96	1,208,576	78	40	593,327	38	318,586	21	0
364-365	'80-01	90,294,518	27,820,673	31	41,824,306	46	14,003,633	16	40	16,729,722	19	(11,090,951)	-12	
364-365	'97-01	7,753,251	983,660	13	1,940,863	25	957,203	12	40	776,345	10	(207,315)	-3	-10
368	'80-01	38,451,935	4,288,943	11	6,803,533	18	2,514,590	7	50	3,401,767	9	(887,176)	-2	
368	'97-01	2,398,678	2,038	0	167,932	7	165,894	7	50	83,966	4	81,928	3	-5
373	'80-01	6,458,603	1,893,184	29	2,183,479	34	290,295	4	50	1,091,740	17	(801,444)	-12	
373	'97-01	254,972	27,594	11	52,302	21	24,708	10	50	26,151	10	(1,443)	-1	-20

A graph and a tabulation which compare the regression equation and the decommissioning cost per MW are presented on pages 147 through 149 of Appendix B. The application of the regression equation values to specific APS units is presented on pages 150 and 151.

The net salvage estimate for the Palo Verde steam generators is based on an engineering estimate of approximately $113 million per unit to replace the steam generators. Removal cost represents 12 percent of this cost and the APS share is 29.1%. Thus, a removal cost of approximately $4 million per unit, $12 million in total, is forecast for the Palo Verde steam generators. Disposal costs related to the steam generators are included in the decommissioning reserve and are not included in the above cost of removal estimate. The estimated removal cost represents 17 percent of the original cost of the steam generators.

Analyses of historical cost of removal and salvage data follow the tables listing the application and development of the decommissioning cost regression equation in Appendix B.

CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

Group Depreciation Procedures. A group procedure for depreciation is appropriate when considering more than a single item of property. Normally, the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

Remaining Life Annual Accruals. For calculating remaining life accrual rates as of December 31, 2002, the estimated book depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and accrued depreciation calculated by the average service life procedure follow. The detailed depreciation calculations are set forth in Appendix C of the report.

Average Service Life Procedure. In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly-weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future whole life depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account, based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life}{Average\ Service\ Life}.$$

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for certain General Plant accounts that represent numerous units of property, but a very small portion of depreciable electric plant in service. The accounts and their amortization periods are as follows:

	Account	Amortization Period, Years
391.0	Furniture and Equipment	20
391.1	PC Equipment	5
391.2	Office Equipment	10
393	Stores Equipment	20
394	Shop Equipment	20
395	Laboratory and Testing Equipment	15
398	Miscellaneous Equipment	20

For calculating annual amortization amounts as of December 31, 2002, the book reserve for each plant account or subaccount is set equal to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the original cost by the amortization period of amortization for vintages within the amortization period. In addition, APS proposes to amortize the difference between the book reserve and the calculated accrued amortization over a three year period for the general plant accounts subject to amortization accounting.

SCE Transmission Line. The annual and accrued depreciation related to the original cost of the transmission line from the Four Corners Power Plant to the interconnection with Southern California Edison (SCE) are based on the rate of 3.25 percent set forth in the agreement between APS and SCE and the age of the line. The annual rate of 3.25 percent is reasonable for this line and consistent with the estimates made for the remainder of the Company's transmission lines.

PART III. RESULTS OF STUDY

PART III. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The estimates of survivor curves and net salvage and the determination of remaining life depreciation accrual rates are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the straight line method, average service life procedure using the remaining life technique based on estimates which reflect considerations of current historical evidence and expected future conditions.

The calculated accrued depreciation represents that portion of the depreciable cost which will not be allocated to future annual expense through depreciation accruals, if current forecasts of service life and salvage materialize and are used as a basis for straight line average service life depreciation accounting.

DESCRIPTION OF STATISTICAL SUPPORT

The service life and salvage estimates were based on judgment which incorporated statistical analyses of retirement data, discussions with management and consideration of estimates made for other electric utility companies. The results of the statistical analyses of service life are presented in Appendix A.

The estimated survivor curves for each account are presented in graphical form. The charts depict the estimated smooth survivor curve and original survivor curve(s), when applicable, related to each specific group. For groups where the original survivor curve was plotted, the calculation of the original life table is also presented.

The analyses of salvage data are presented in Appendix B titled, "Net Salvage Statistics." The tabulations present annual cost of removal and salvage data, three-year moving averages and the most recent five-year average. Data are shown in dollars and as percentages of original costs retired.

DESCRIPTION OF DEPRECIATION TABULATIONS

A summary of the results of the study, as applied to the original cost of electric plant at December 31, 2002, is presented in Schedule 1 on pages III-4 through III-23 of this report. Schedule 1 sets forth, by depreciable category, the estimated survivor curve, net salvage, original cost, book depreciation reserve at December 31, 2002, future book accruals, calculated annual accrual amount and rate, and composite remaining life for utility plant.

The tables of the calculated annual and accrued depreciation are presented in account sequence in Appendix C. The tables indicate the estimated survivor curve and salvage percent for the account and set forth for each installation year the original cost, the calculated annual accrual rate and amount, and the calculated accrued depreciation factor and amount.

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
PLANT IN SERVICE										
STEAM PRODUCTION PLANT										
311	Structures and Improvements									
	Cholla Unit 1	06-2017	75 - S1.5	(20)	2,144,789	1,964,146	609,602	14.0	43,523	2.03
	Cholla Unit 2	06-2033	75 - S1.5	(20)	5,022,179	2,346,306	3,680,309	29.0	126,743	2.52
	Cholla Unit 3	06-2035	75 - S1.5	(20)	9,583,277	6,113,726	5,386,207	29.9	180,314	1.88
	Cholla Common	06-2035	75 - S1.5	(20)	36,234,550	22,949,841	20,531,618	29.9	685,872	1.89
	Four Corners Units 1-3	06-2016	75 - S1.5	(20)	15,972,927	7,395,910	11,771,602	13.3	885,732	5.55
	Four Corners Units 4-5	06-2031	75 - S1.5	(20)	9,195,585	5,253,259	5,781,443	26.8	216,098	2.35
	Four Corners Common	06-2031	75 - S1.5	(20)	3,946,871	2,790,814	1,945,433	26.8	72,563	1.84
	Navajo Units 1-3	06-2026	75 - S1.5	(20)	27,152,517	11,359,467	21,223,557	22.8	929,321	3.42
	Ocotillo Units 1-2	06-2020	75 - S1.5	(20)	3,787,972	1,882,068	2,663,500	17.1	155,535	4.11
	Saguaro Units 1-2	06-2014	75 - S1.5	(20)	2,446,832	2,011,377	924,823	11.3	81,704	3.34
	Yucca Unit 1	12-2016	75 - S1.5	(20)	462,567	471,080	84,000	13.1	6,405	1.38
	Total Account 311				115,950,066	64,537,994	74,602,094		3,383,810	2.92
312	Boiler Plant Equipment									
	Cholla Unit 1	06-2017	48 - L2	(20)	26,431,681	17,353,280	14,364,742	13.4	1,074,426	4.06
	Cholla Unit 2	06-2033	48 - L2	(20)	140,612,492	93,979,314	74,755,676	22.0	3,393,069	2.41
	Cholla Unit 3	06-2035	48 - L2	(20)	100,448,965	63,309,215	57,229,546	22.9	2,500,521	2.49
	Cholla Common	06-2035	48 - L2	(20)	22,626,051	11,951,401	15,199,859	24.8	613,196	2.71
	Four Corners Units 1-3	06-2016	48 - L2	(20)	197,139,757	90,637,620	145,930,090	12.7	11,533,490	5.85
	Four Corners Units 4-5	06-2031	48 - L2	(20)	111,591,873	60,671,520	73,238,729	22.1	3,320,980	2.98
	Four Corners Common	06-2031	48 - L2	(20)	3,290,391	2,787,122	1,161,347	22.8	50,863	1.55
	Navajo Units 1-3	06-2026	48 - L2	(20)	149,350,243	65,220,188	114,000,103	20.6	5,528,022	3.70
	Ocotillo Units 1-2	06-2020	48 - L2	(20)	24,152,351	18,891,592	10,091,228	15.2	665,415	2.76
	Saguaro Units 1-2	06-2014	48 - L2	(20)	24,387,712	17,510,312	11,754,943	11.1	1,062,280	4.36
	Total Account 312				800,031,516	442,311,564	517,726,263		29,742,262	3.72
314	Turbogenerator Units									
	Cholla Unit 1	06-2017	65 - R2	(20)	10,417,373	8,187,222	4,313,626	14.0	307,127	2.95
	Cholla Unit 2	06-2033	65 - R2	(20)	28,551,889	18,457,272	15,804,995	27.5	574,578	2.01
	Cholla Unit 3	06-2035	65 - R2	(20)	39,626,197	19,942,381	27,609,055	29.7	929,156	2.34
	Cholla Common	06-2035	65 - R2	(20)	631,278	389,822	367,711	29.0	12,687	2.01
	Four Corners Units 1-3	06-2016	65 - R2	(20)	36,412,926	24,997,649	18,697,862	13.1	1,427,354	3.92
	Four Corners Units 4-5	06-2031	65 - R2	(20)	14,488,238	8,049,950	9,335,936	26.3	355,319	2.45
	Four Corners Common	06-2031	65 - R2	(20)	1,726,164	1,965,225	106,172	23.3	4,559	0.26

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

Depreciable Group (1)	Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/02 (5)	Book Accumulated Depreciation (6)	Future Accruals (7)	Composite Remaining Life (8)	Calculated Annual Accrual Amount (9)	Calculated Annual Accrual Rate (10)=(9)/(5)
Navajo Units 1-3	06-2026	65 - R2	(20)	24,387,110	15,363,242	13,901,288	22.0	632,931	2.60
Ocotillo Units 1-2	06-2020	65 - R2	(20)	15,517,601	13,579,702	5,041,420	16.8	300,851	1.94
Saguaro Units 1-2	06-2014	65 - R2	(20)	16,259,698	12,946,682	6,564,957	11.2	588,188	3.62
Total Account 314				188,018,474	123,879,147	101,743,022		5,132,750	2.73
315 Accessory Electric Equipment									
Cholla Unit 1	06-2017	60 - R2.5	(20)	4,756,906	3,537,479	2,170,809	13.9	156,073	3.28
Cholla Unit 2	06-2033	60 - R2.5	(20)	42,235,618	29,787,215	20,895,527	26.8	778,409	1.84
Cholla Unit 3	06-2035	60 - R2.5	(20)	29,917,206	18,952,154	16,948,493	28.6	591,676	1.98
Cholla Common	06-2035	60 - R2.5	(20)	4,476,001	2,804,488	2,566,712	28.7	89,341	2.00
Four Corners Units 1-3	06-2016	60 - R2.5	(20)	16,353,282	6,735,295	12,888,643	13.2	978,802	5.99
Four Corners Units 4-5	06-2031	6C - R2.5	(20)	9,183,206	5,249,818	5,770,029	25.9	222,550	2.42
Four Corners Common	06-2031	60 - R2.5	(20)	2,596,719	3,017,438	98,625	21.9	4,503	0.17
Navajo Units 1-3	06-2026	60 - R2.5	(20)	20,226,194	12,812,227	11,459,205	22.0	521,434	2.58
Ocotillo Units 1-2	06-2020	60 - R2.5	(20)	2,407,622	2,349,290	539,855	16.3	33,220	1.38
Saguaro Units 1-2	06-2014	60 - R2.5	(20)	2,654,661	2,598,693	586,901	11.2	52,354	1.97
Total Account 315				134,807,415	87,844,097	73,924,799		3,428,362	2.54
316 Miscellaneous Power Plant Equipment									
Cholla Unit 1	06-2017	40 - R2	(20)	2,315,189	849,777	1,928,453	13.5	142,907	6.17
Cholla Unit 2	06-2033	40 - R2	(20)	4,846,431	2,942,292	2,873,425	22.1	129,898	2.68
Cholla Unit 3	06-2035	40 - R2	(20)	4,138,531	2,218,283	2,747,953	23.8	115,595	2.79
Cholla Common	06-2035	40 - R2	(20)	7,096,069	2,519,563	5,995,721	25.8	232,179	3.27
Four Corners Units 1-3	06-2016	40 - R2	(20)	4,330,612	557,644	4,639,090	13.1	354,982	8.20
Four Corners Units 4-5	06-2031	40 - R2	(20)	3,304,340	1,499,998	2,465,211	23.0	107,103	3.24
Four Corners Common	06-2031	40 - R2	(20)	8,133,224	3,516,915	6,242,954	23.2	269,374	3.31
Navajo Units 1-3	06-2026	40 - R2	(20)	11,805,250	5,178,470	8,987,830	20.2	444,171	3.76
Ocotillo Units 1-2	06-2020	40 - R2	(20)	3,711,192	1,047,634	3,405,795	16.2	210,098	5.66
Saguaro Units 1-2	06-2014	40 - R2	(20)	3,191,024	1,012,665	2,816,563	10.9	257,730	8.08
Yucca Unit 1	12-2016	40 - R2	(20)	452,868	353,040	190,401	12.2	15,667	3.46
Total Account 316				53,324,730	21,696,281	42,293,396		2,279,704	4.28
TOTAL STEAM PRODUCTION PLANT				1,292,132,201	740,269,083	810,289,574		43,966,888	

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
NUCLEAR PRODUCTION PLANT										
321	Structures and Improvements									
	Palo Verde Unit 1	12-2024	65 - R2.5	0	161,039,432	68,224,238	92,815,194	21.2	4,384,691	2.72
	Palo Verde Unit 2	12-2025	65 - R2.5	0	88,415,270	37,058,726	51,356,544	22.0	2,331,149	2.64
	Palo Verde Unit 3	03-2027	65 - R2.5	0	159,591,077	62,020,595	97,570,482	23.3	4,195,723	2.63
	Palo Verde Water Reclamation	03-2027	65 - R2.5	0	125,593,913	50,775,392	74,818,521	23.2	3,225,203	2.57
	Palo Verde Common	03-2027	65 - R2.5	0	96,127,309	38,045,036	60,082,273	23.2	2,586,955	2.64
	Total Account 321				632,767,001	256,123,987	376,643,014		16,723,721	2.64
322	Reactor Plant Equipment									
	Palo Verde Unit 1	12-2024	70 - R1	(2)	359,545,213	144,992,453	221,743,665	20.6	10,760,567	2.99
	Palo Verde Unit 2	12-2025	70 - R1	(2)	176,362,235	64,407,419	115,482,062	21.5	5,377,429	3.05
	Palo Verde Unit 3	03-2027	70 - R1	(2)	322,750,700	118,393,045	210,812,669	22.6	9,331,561	2.89
	Palo Verde Water Reclamation	03-2027	70 - R1	(2)	123,313	5,190	120,589	23.0	5,251	4.26
	Palo Verde Common	03-2027	70 - R1	(2)	26,449,873	9,772,755	17,206,115	22.6	760,717	2.88
	Total Account 322				885,231,334	337,570,862	565,365,100		26,235,525	2.96
322.1	Reactor Plant Equipment - Steam Generators									
	Palo Verde Unit 1	12-2005	Square	(17)	30,722,375	31,766,117	4,179,062	3.0	1,393,021	4.53
	Palo Verde Unit 2	12-2003	Square	(17)	15,870,053	17,917,124	650,838	1.0	650,838	4.10
	Palo Verde Unit 3	12-2007	Square	(17)	25,413,317	23,597,351	6,136,230	5.0	1,227,246	4.83
	Total Account 322.1				72,005,745	73,280,592	10,966,130		3,271,105	4.54
323	Turbogenerator Units									
	Palo Verde Unit 1	12-2024	60 - S0	(2)	117,808,078	50,929,473	69,234,765	19.9	3,471,147	2.95
	Palo Verde Unit 2	12-2025	60 - S0	(2)	76,754,224	30,390,765	47,898,546	20.8	2,307,463	3.01
	Palo Verde Unit 3	03-2027	60 - S0	(2)	142,895,088	55,717,208	90,035,783	21.8	4,123,870	2.89
	Palo Verde Water Reclamation	03-2027	60 - S0	(2)	217,707	54,310	167,751	22.0	7,629	3.50
	Palo Verde Common	03-2027	60 - S0	(2)	1,223,879	(131,408)	1,379,764	22.2	62,190	5.08
	Total Account 323				338,898,976	136,960,348	208,716,609		9,972,299	2.94
324	Accessory Electric Equipment									
	Palo Verde Unit 1	12-2024	45 - R3	(2)	115,495,170	51,830,648	65,974,427	20.0	3,292,508	2.85
	Palo Verde Unit 2	12-2025	45 - R3	(2)	50,119,388	20,346,865	30,774,911	20.9	1,470,132	2.93

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals Related to Electric Plant at December 31, 2002

	Depreciable Group (1)	Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/02 (5)	Book Accumulated Depreciation (6)	Future Accruals (7)	Composite Remaining Life (8)	Calculated Annual Accrual Amount (9)	Calculated Annual Accrual Rate (10)=(9)/(5)
	Palo Verde Unit 3	03-2027	45 - R3	(2)	89,143,623	36,276,331	54,650,164	22.1	2,475,838	2.78
	Palo Verde Common	03-2027	45 - R3	(2)	17,918,193	7,373,717	10,902,840	22.0	495,396	2.76
	Total Account 324				272,676,374	115,827,561	162,302,342		7,733,874	2.84
325	Miscellaneous Power Plant Equipment									
	Palo Verde Unit 1	12-2024	35 - R0.5	(2)	29,671,405	17,609,436	12,655,399	17.7	716,211	2.41
	Palo Verde Unit 2	12-2025	35 - R0.5	(2)	26,389,406	13,408,579	13,508,616	18.7	722,783	2.74
	Palo Verde Unit 3	03-2027	35 - R0.5	(2)	27,284,046	15,083,087	12,746,639	19.2	663,956	2.43
	Palo Verde Water Reclamation	03-2027	35 - R0.5	(2)	88,819	46,552	44,043	19.5	2,261	2.55
	Palo Verde Common	03-2027	35 - R0.5	(2)	48,459,510	21,228,993	28,199,708	19.4	1,453,065	3.00
	Total Account 325				131,893,186	67,376,647	67,154,405		3,558,276	2.70
	TOTAL NUCLEAR PRODUCTION PLANT				**2,333,472,616**	**987,139,997**	**1,391,147,600**		**67,494,800**	
	HYDRO PRODUCTION PLANT									
331	Structures and Improvements	12-2004	Square	0	100,878	100,878	0	0.0	0	0.00
332	Reservoirs, Dams and Waterways	12-2004	Square	0	991,936	1,105,086	(113,150)	0.0	0	0.00
333	Water Wheels, Turbines and Generators	12-2004	Square	0	157,196	157,196	0	0.0	0	0.00
334	Accessory Electric Equipment	12-2004	Square	0	627,611	627,611	0	0.0	0	0.00
335	Miscellaneous Power Plant Equipment	12-2004	Square	0	126,018	126,018	0	0.0	0	0.00
336	Roads, Railroads and Bridges	12-2004	Square	0	77,427	77,427	0	0.0	0	0.00
	Hydro Decomissioning Costs				-	7,864,531	5,335,469 (a)	2.0	2,667,735	
	TOTAL HYDRO PRODUCTION PLANT				**2,081,066**	**10,058,747**	**5,222,319**		**2,667,735**	
	OTHER PRODUCTION PLANT									
341	Structures and Improvements									
	Douglas CT	06-2017	80 - S1	(5)	4,562	3,417	1,373	13.9	99	2.17
	Ocotillo CT 1 - 2	06-2017	80 - S1	(5)	328,749	309,919	35,268	14.5	2,439	0.74
	Saguaro CT	06-2017	80 - S1	(5)	1,288,525	360,293	992,659	14.4	69,056	5.36
	Solar Unit 1		12 - SQ	0	375,512	237,890	137,622	3.6	38,056	10.13
	West Phoenix CT 1 - 2	06-2017	80 - S1	(5)	510,951	475,096	61,403	14.2	4,328	0.85
	West Phoenix Combined Cycle 1 - 3	06-2031	80 - S1	(5)	6,706,722	3,949,614	3,092,446	28.1	110,243	1.64
	Yucca CT 1 - 4	06-2016	80 - S1	(5)	452,751	155,293	320,095	13.4	23,962	5.29
	Total Account 341				9,667,772	5,491,522	4,640,866		248,183	2.57

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
342	Fuel Holders, Products and Accessories									
	Douglas CT	06-2017	70 - S1	(5)	137,759	73,566	71,081	14.0	5,063	3.68
	Ocotillo CT 1 - 2	06-2017	70 - S1	(5)	719,859	359,329	396,523	14.0	28,225	3.92
	Saguaro CT	06-2017	70 - S1	(5)	1,304,977	804,476	565,750	14.0	40,547	3.11
	West Phoenix CT 1 - 2	06-2017	70 - S1	(5)	1,437,533	840,769	668,641	14.0	47,921	3.33
	West Phoenix Combined Cycle 1 - 3	06-2031	70 - S1	(5)	19,343,993	2,978,088	17,333,104	27.7	624,716	3.23
	Yucca CT 1 - 4	06-2016	70 - S1	(5)	3,232,217	2,710,284	683,545	12.9	52,931	1.64
	Total Account 342				26,176,338	7,766,512	19,718,644		799,403	3.05
343	Prime Movers									
	Douglas CT	06-2017	70 - L1.5	0	1,101,449	1,102,406	(957)	0.0	0	0.00
	Ocotillo CT 1 - 2	06-2017	70 - L1.5	0	6,679,324	6,127,017	552,307	14.1	39,158	0.59
	Saguaro CT	06-2017	70 - L1.5	0	8,102,651	6,441,288	1,661,363	13.8	120,086	1.48
	West Phoenix CT 1 - 2	06-2017	70 - L1.5	0	8,802,636	6,428,854	2,373,782	14.2	167,290	1.90
	Yucca CT 1 - 4	06-2016	70 - L1.5	0	7,920,584	8,796,851	(876,267)	0.0	0	0.00
	Total Account 343				32,606,644	28,896,416	3,710,228		326,534	1.00
344	Generators and Devices									
	Douglas CT	06-2017	37 - R3	0	551,765	546,431	5,334	9.7	549	0.10
	Ocotillo CT 1 - 2	06-2017	37 - R3	0	6,402,044	2,369,080	4,032,964	13.6	296,448	4.63
	Saguaro CT	06-2017	37 - R3	0	4,185,247	1,954,137	2,231,110	13.0	171,743	4.10
	Solar Unit 1		12 - SQ	0	6,933,081	3,041,951	3,891,130	7.8	498,118	7.18
	West Phoenix CT 1 - 2	06-2017	37 - R3	0	4,115,901	2,407,953	1,707,948	12.3	138,912	3.38
	West Phoenix Combined Cycle 1 - 3	06-2031	37 - R3	(2)	81,920,222	11,064,493	72,494,134	26.2	2,765,872	3.38
	Yucca CT 1 - 4	06-2016	37 - R3	0	5,395,818	3,751,109	1,644,709	11.6	141,655	2.63
	Total Account 344				109,504,078	25,135,154	86,007,329		4,013,297	3.66
345	Accessory Electric Equipment									
	Douglas CT	06-2017	50 - S2	0	353,277	296,417	56,860	13.1	4,339	1.23
	Ocotillo CT 1 - 2	06-2017	50 - S2	0	1,494,636	1,158,282	336,354	13.2	25,401	1.70
	Saguaro CT	06-2017	50 - S2	0	1,715,774	1,133,530	582,244	13.4	43,562	2.54
	Solar Unit 1		12 - SQ	0	169,527	12,853	156,674	9.9	15,865	9.36

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
	West Phoenix CT 1 - 2	06-2017	50 - S2	0	1,557,744	1,079,614	478,130	13.2	36,163	2.32
	West Phoenix Combined Cycle 1 - 3	06-2031	50 - S2	0	11,925,645	3,758,130	8,167,515	27.8	293,998	2.47
	Yucca CT 1 - 4	06-2016	50 - S2	0	2,166,526	1,818,547	347,979	13.0	26,820	1.24
	Total Account 345				19,383,129	9,257,373	10,125,756		446,148	2.30
346	Miscellaneous Power Plant Equipment									
	Douglas CT	06-2017	70 - L1	0	40,913	29,882	11,031	13.8	798	1.95
	Ocotillo CT 1 - 2	06-2017	70 - L1	0	553,173	460,255	92,918	14.0	6,650	1.20
	Saguaro CT	06-2017	70 - L1	0	790,906	388,367	402,539	14.1	28,508	3.60
	West Phoenix CT 1 - 2	06-2017	70 - L1	0	957,431	479,217	478,214	14.1	33,908	3.54
	West Phoenix Combined Cycle 1 - 3	06-2031	70 - L1	0	2,608,877	1,714,480	894,397	26.6	33,618	1.29
	Yucca CT 1 - 4	06-2016	70 - L1	0	427,175	411,833	15,342	13.2	1,166	0.27
	Total Account 346				5,378,475	3,484,034	1,894,441		104,648	1.95
	TOTAL OTHER PRODUCTION PLANT				**202,716,436**	**80,031,011**	**126,097,264**		**5,938,213**	
	TRANSMISSION PLANT									
352	Structures and Improvements		50 - R4	(5)	27,618,299	8,135,201	20,864,015	35.2	592,619	2.15
352.5	Structures and Improvements - SCE 500 KV Line				409,725	296,895	235,747		13,316	3.25 (b)
353	Station Equipment		42 - R3	0	428,736,305	173,966,733	254,769,572	31.2	8,167,649	1.91
353.5	Station Equipment - SCE 500 KV Line				7,747,282	6,464,972	3,606,497		251,787	3.25 (b)
354	Towers and Fixtures		60 - R3	(35)	83,464,531	39,991,439	72,685,678	38.3	1,899,472	2.28
354.5	Towers and Fixtures - SCE 500 KV Line				13,752,584	13,542,259	4,336,101		446,959	3.25 (b)
355	Poles and Fixtures - Wood		48 - R1.5	(35)	91,126,939	33,590,493	89,430,875	38.5	2,321,504	2.55
355.1	Poles and Fixtures - Steel		55 - R3	(15)	83,067,888	22,282,935	73,245,140	45.1	1,625,822	1.96
355.5	Poles and Fixtures - SCE 500 KV Line				930,308	341,908	867,492		30,235	3.25 (b)
356	Overhead Conductors and Devices		55 - R3	(35)	205,771,417	70,439,236	207,352,178	38.5	5,391,852	2.62
356.5	Overhead Conductors and Devices - SCE 500 KV Line				22,653,515	23,670,862	5,778,708		736,239	3.25 (b)
357	Underground Conduit		48 - S1.5	(10)	10,444,362	2,989,523	8,499,278	35.7	237,777	2.28
358	Underground Conductors and Devices		40 - R3	(10)	18,551,254	6,336,374	14,070,005	26.3	534,608	2.88
	TOTAL TRANSMISSION PLANT				994,274,409	402,048,830	755,741,286		22,249,839	

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

	Depreciable Group (1)	Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/02 (5)	Book Accumulated Depreciation (6)	Future Accruals (7)	Composite Remaining Life (8)	Calculated Annual Accrual Amount (9)	Calculated Annual Accrual Rate (10)=(9)/(5)
	ISTRIBUTION PLANT									
361	Structures and Improvements		45 - R2.5	(10)	25,815,042	7,749,290	20,647,256	33.1	623,356	2.41
362	Station Equipment		38 - S0	0	212,357,577	70,802,963	141,554,614	31.8	4,456,837	2.10
364	Poles, Towers and Fixtures - Wood		38 - R0.5	(10)	284,200,711	94,139,326	218,481,457	30.9	7,076,374	2.49
364.1	Poles, Towers and Fixtures - Steel		50 - R3	(5)	53,919,651	5,138,171	51,477,465	46.6	1,105,404	2.05
365	Overhead Conductors and Devices		53 - O1	(10)	218,856,780	58,922,434	181,820,025	47.7	3,810,605	1.74
366	Underground Conduit		55 - R1.5	(5)	425,723,116	51,496,065	395,513,205	49.4	8,009,076	1.88
367	Underground Conductors and Devices		29 - L1	(5)	805,505,783	227,200,974	618,580,099	22.9	27,036,316	3.36
368	Line Transformers		36 - R3	(5)	486,837,053	188,298,226	322,880,680	24.6	13,147,552	2.70
369	Services		37 - S2	(10)	242,404,812	86,204,425	180,440,873	27.9	6,463,178	2.67
370	Meters		23 - R1	0	91,330,710	36,185,262	55,145,448	13.5	4,086,660	4.47
370.1	Electronic Meters		12 - S2	0	54,691,249	11,298,055	43,393,194	8.7	4,987,610	9.12
371	Installations On Customers Premises		30 - R1	(20)	25,335,831	8,708,344	21,694,654	22.9	945,981	3.73
373	Street Lighting and Signal Systems		35 - R2	(20)	57,185,737	19,618,266	49,004,615	25.9	1,890,534	3.31
	TOTAL DISTRIBUTION PLANT				2,984,164,052	865,761,801	2,300,633,585		83,639,483	
	ENERAL PLANT									
390	Structures and Improvements		39 - R1	(15)	96,667,435	30,654,079	80,513,474	30.7	2,624,392	2.71
391	Office Furniture and Equipment - Furniture		20 - SQ	0	19,919,640	9,897,448	10,022,192	10.1	994,570	5.00 (c)
	Reserve Variance Amortization					0	0	3.0 (d)	0	
391.1	Office Furniture and Equipment - Pc Equip		5 - SQ	0	38,654,946	21,283,348	17,371,598	2.7	6,467,368	20.00 (c)
	Reserve Variance Amortization					(7,055,994)	7,055,994	3.0 (d)	2,351,998	
391.2	Office Furniture and Equipment - Equipment		10 - SQ	0	7,652,923	4,070,284	3,582,639	7.8	461,909	10.00 (c)
	Reserve Variance Amortization					0	0	3.0 (d)	0	
393	Stores Equipment		20 - SQ	0	1,227,371	1,142,564	84,807	2.8	29,921	5.00 (c)
	Reserve Variance Amortization					(303,976)	303,976	3.0 (d)	101,325	
394	Tools, Shop and Garage Equipment		20 - SQ	0	12,673,031	3,989,281	8,683,750	13.7	633,652	5.00 (c)
	Reserve Variance Amortization					(690,684)	690,684	3.0 (d)	230,228	
395	Laboratory Equipment		15 - SQ	0	1,350,583	1,082,162	268,421	3.6	75,200	6.67 (c)
	Reserve Variance Amortization					(38,339)	38,339	3.0 (d)	12,780	
397	Communication Equipment		19 - S1.5	0	94,309,691	36,587,109	57,722,582	12.0	4,811,742	5 10
398	Miscellaneous Equipment		20 - SQ	0	1,336,404	584,352	752,052	11.5	65,276	5.00 (c)
	Reserve Variance Amortization					62,877	(62,877)	3.0 (d)	(20,959)	
	TOTAL GENERAL PLANT				273,792,024	101,264,511	187,027,631		18,839,402	
	OTAL DEPRECIABLE PLANT STUDIED				8,082,632,804	3,186,573,980	5,576,159,259		244,796,360	

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals Related to Electric Plant at December 31, 2002

Depreciable Group (1)	Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/02 (5)	Book Accumulated Depreciation (6)	Future Accruals (7)	Composite Remaining Life (8)	Calculated Annual Accrual Amount (9)	Calculated Annual Accrual Rate (10)=(9)/(5)
STEAM PRODUCTION PLANT NOT STUDIED									
311 Structures and Improvements - West Phoenix Units 4 & 6				0	80,895				
312 Boiler Plant Equipment - West Phoenix Units 4 & 6				0	300,097				
312 Boiler Plant Equipment - Yucca Unit 1				425,323	441,994				
314 Turbogenerator Units - West Phoenix Units 4 & 6				0	314,512				
314 Turbogenerator Units - Yucca Unit 1				184,916	188,319				
315 Accessory Electric Equipment - West Phoenix Units 4 & 6				33,968	83,338				
315 Accessory Electric Equipment - Yucca Unit 1				182,084	185,435				
316 Misc. Power Plant Equipment-West Phoenix Units 4 & 6				17,267	0				
TOTAL STEAM PRODUCTION PLANT NOT STUDIED				**843,558**	**1,594,590**				
GENERAL PLANT NOT STUDIED									
392 Vehicles				28,410,886	20,605,998				
396 Power Operated Equipment				27,947,651	18,603,989				
TOTAL GENERAL PLANT NOT STUDIED				**56,358,537**	**39,209,987**				
OTHER PROPERTY NOT STUDIED									
Intangible Plant									
301 Organization				73,639					
302 Franchises and Consents				883,584					
303 Miscellaneous Intangible Plant				201,550,375					
Leased Property									
321 Structures and Improvements				1,633,193					
322 Reactor Plant Equipment				9,670,223					
323 Turbogenerator Units				2,705,885					
324 Accessory Electric Equipment				944,788					
325 Miscellaneous Power Plant Equipment				563,135					
361 Structures and Improvements				195,512					
368 Line Transformers				179,394					
371 Installations On Customers Premises				60,386					
390 Structures and Improvements				11,160,324					
397 Communication Equipment				245,938					
TOTAL OTHER PROPERTY NOT STUDIED				229,866,377	120,727,768				
TOTAL DEPRECIABLE PLANT IN SERVICE				8,369,701,276	3,348,106,325				

ARIZONA PUBLIC SERVICE COMPANY

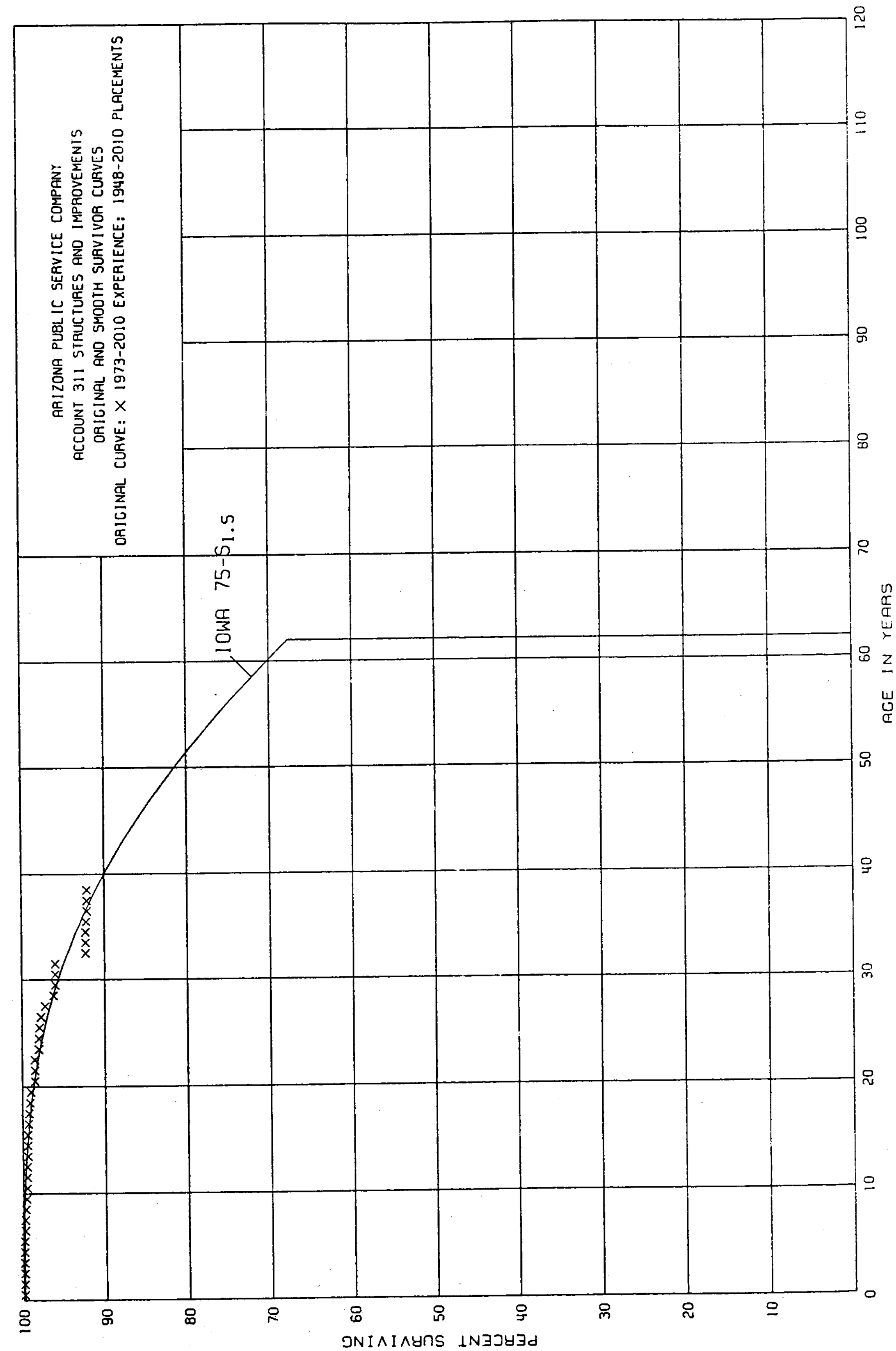
Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

Depreciable Group		Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
NONDEPRECIABLE PLANT										
310	Land and Land Rights				3,295,268					
320	Land and Land Rights				3,399,728					
330	Land and Land Rights				64,500					
340	Land and Land Rights				28,192					
350	Land and Land Rights				50,808,274					
360	Land and Land Rights				26,755,119					
389	Land and Land Rights				7,327,436					
TOTAL NONDEPRECIABLE					91,678,517					
TOTAL PLANT IN SERVICE					8,461,379,793					

(a) Future Accruals Related to Hydro Decomissioning are Equal to the Expected Decomissioning Costs of 13.2 Million less the Book Accumulated Depreciation
(b) Assets Related to the 500 KV SCE Transmission Line are Depreciated at a 3.25 Rate
(c) Amortization Rate Applicable to those Vintages Within the Amortization Period
(d) Reserve Variances Related to General Plant Amortization Accounts are Amortized Over 3 Years

APPENDIX A

SERVICE LIFE STATISTICS


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 311 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1973-2010 EXPERIENCE; 1948-2010 PLACEMENTS
IOWA 75-S1.5
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1948-2010 EXPERIENCE BAND 1973-2010

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	145,725,484		0.0000	1.0000	100.00
0.5	142,882,984		0.0000	1.0000	100.00
1.5	142,023,381		0.0000	1.0000	100.00
2.5	142,279,737	2,000	0.0000	1.0000	100.00
3.5	145,020,116	208,633	0.0014	0.9986	100.00
4.5	137,896,820	9,116	0.0001	0.9999	99.86
5.5	137,585,004	30,752	0.0002	0.9998	99.85
6.5	136,542,207	51,000	0.0004	0.9996	99.83
7.5	121,786,139	145,270	0.0012	0.9988	99.79
8.5	121,139,290	46,511	0.0004	0.9996	99.67
9.5	125,269,039	158,367	0.0013	0.9987	99.63
10.5	122,339,175	4,570	0.0000	1.0000	99.50
11.5	119,151,627	18,177	0.0002	0.9998	99.50
12.5	118,113,243	93,298	0.0008	0.9992	99.48
13.5	95,144,116	2,086	0.0000	1.0000	99.40
14.5	93,219,009	10,591	0.0001	0.9999	99.40
15.5	92,401,512	52,130	0.0006	0.9994	99.39
16.5	90,387,953	106,376	0.0012	0.9988	99.33
17.5	87,845,596	135,412	0.0015	0.9985	99.21
18.5	88,150,041	33,171	0.0004	0.9996	99.06
19.5	88,306,458	445,435	0.0050	0.9950	99.02
20.5	87,759,593	45,000	0.0005	0.9995	98.52
21.5	86,866,471	4,872	0.0001	0.9999	98.47
22.5	84,636,192	402,897	0.0048	0.9952	98.46
23.5	83,501,354	15,838	0.0002	0.9998	97.99
24.5	80,771,367	69,176	0.0009	0.9991	97.97
25.5	77,613,845	176,186	0.0023	0.9977	97.88
26.5	70,059,969	309,797	0.0044	0.9956	97.65
27.5	67,474,975	738,454	0.0109	0.9891	97.22
28.5	59,535,155	89,205	0.0015	0.9985	96.16
29.5	51,622,997		0.0000	1.0000	96.02
30.5	39,527,686	28,556	0.0007	0.9993	96.02
31.5	37,318,208	1,417,795	0.0380	0.9620	95.95
32.5	19,270,167		0.0000	1.0000	92.30
33.5	18,156,622	8,249	0.0005	0.9995	92.30
34.5	13,569,377	9,334	0.0007	0.9993	92.25
35.5	10,415,064	9,089	0.0009	0.9991	92.19
36.5	7,772,495		0.0000	1.0000	92.11
37.5	7,728,961		0.0000	1.0000	92.11
38.5	7,440,782	295,610	0.0397	0.9603	92.11

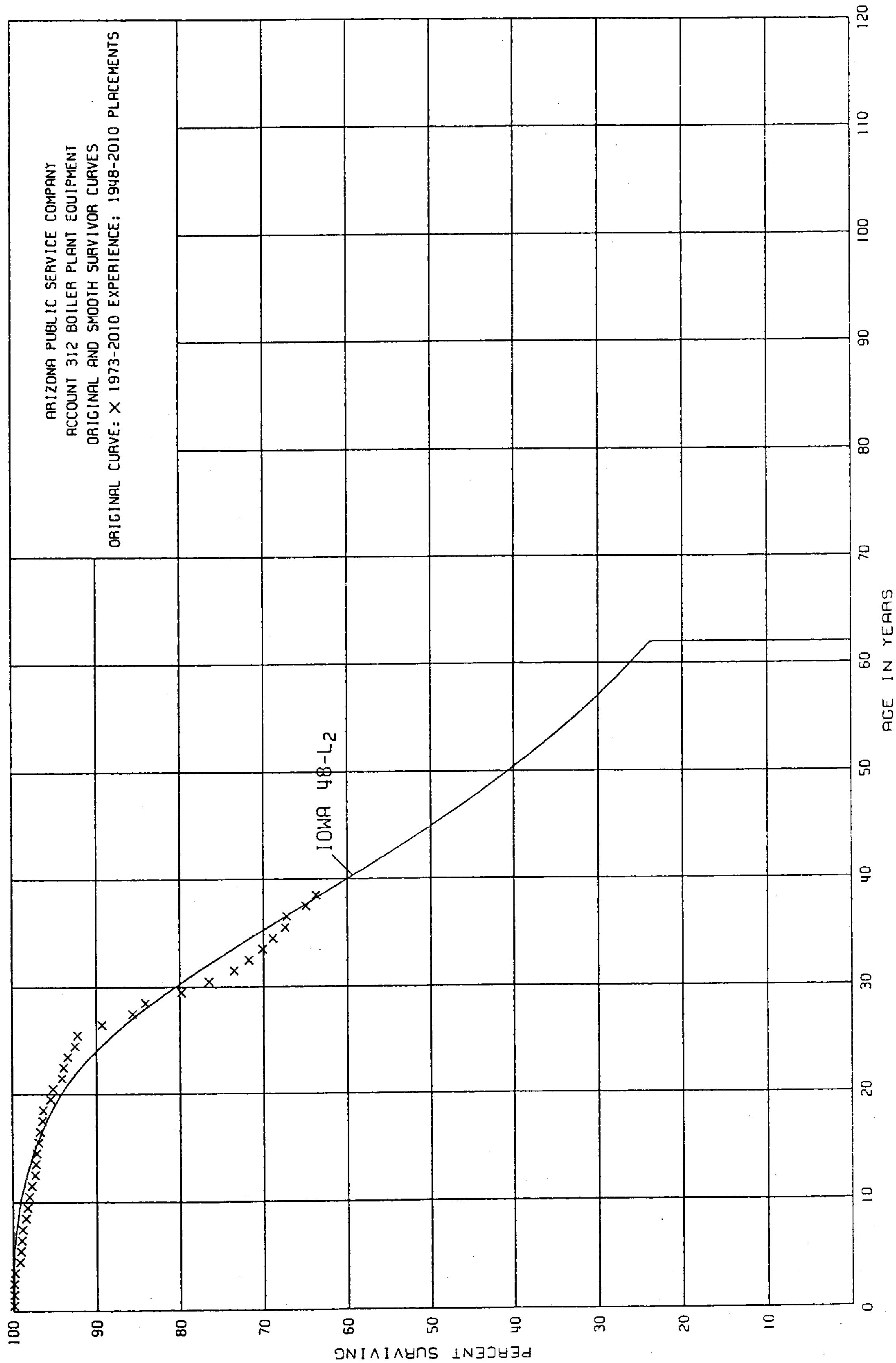
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1948-2010 EXPERIENCE BAND 1973-2010

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,520,666	991,626	0.1521	0.8479	88.45
40.5	5,157,896	1,302,651	0.2526	0.7474	75.00
41.5	3,610,024	84,566	0.0234	0.9766	56.06
42.5	3,535,087		0.0000	1.0000	54.75
43.5	3,512,249		0.0000	1.0000	54.75
44.5	3,492,656	344,085	0.0985	0.9015	54.75
45.5	2,986,714	879,481	0.2945	0.7055	49.36
46.5	1,496,464		0.0000	1.0000	34.82
47.5	1,412,689	160,536	0.1136	0.8864	34.82
48.5	2,193,457		0.0000	1.0000	30.86
49.5	2,102,098		0.0000	1.0000	30.86
50.5	2,028,068		0.0000	1.0000	30.86
51.5	1,933,964		0.0000	1.0000	30.86
52.5	1,918,057		0.0000	1.0000	30.86
53.5	2,528,466		0.0000	1.0000	30.86
54.5	2,527,583		0.0000	1.0000	30.86
55.5	2,527,583		0.0000	1.0000	30.86
56.5	1,669,625		0.0000	1.0000	30.86
57.5	620,980		0.0000	1.0000	30.86
58.5	620,980		0.0000	1.0000	30.86
59.5	620,980		0.0000	1.0000	30.86
60.5	620,980		0.0000	1.0000	30.86
61.5	620,980		0.0000	1.0000	30.86
62.5					30.86


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 312 BOILER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1973-2010 EXPERIENCE; 1948-2010 PLACEMENTS
IOWA 48-L2
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1948-2010 EXPERIENCE BAND 1973-2010

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,231,200,262	4,335	0.0000	1.0000	100.00
0.5	1,219,701,527	400,427	0.0003	0.9997	100.00
1.5	1,176,962,172	1,083,231	0.0009	0.9991	99.97
2.5	1,126,549,776	977,858	0.0009	0.9991	99.88
3.5	987,759,265	5,701,103	0.0058	0.9942	99.79
4.5	867,930,823	695,968	0.0008	0.9992	99.21
5.5	832,755,183	957,662	0.0011	0.9989	99.13
6.5	811,462,973	1,000,101	0.0012	0.9988	99.02
7.5	791,828,181	3,349,923	0.0042	0.9958	98.90
8.5	749,214,968	1,154,661	0.0015	0.9985	98.48
9.5	773,117,847	1,776,706	0.0023	0.9977	98.33
10.5	760,104,474	2,703,347	0.0036	0.9964	98.10
11.5	702,469,895	2,527,110	0.0036	0.9964	97.75
12.5	692,346,073	757,114	0.0011	0.9989	97.40
13.5	654,930,234	585,153	0.0009	0.9991	97.29
14.5	642,429,076	1,044,577	0.0016	0.9984	97.20
15.5	639,956,908	1,544,420	0.0024	0.9976	97.04
16.5	633,550,217	1,918,234	0.0030	0.9970	96.81
17.5	630,391,217	937,817	0.0015	0.9985	96.52
18.5	633,409,723	6,045,232	0.0095	0.9905	96.38
19.5	617,501,437	1,881,755	0.0030	0.9970	95.46
20.5	598,767,438	6,958,439	0.0116	0.9884	95.17
21.5	580,127,947	1,248,549	0.0022	0.9978	94.07
22.5	571,194,091	3,001,793	0.0053	0.9947	93.86
23.5	557,610,113	5,400,837	0.0097	0.9903	93.36
24.5	536,479,287	1,507,628	0.0028	0.9972	92.45
25.5	529,217,164	16,818,495	0.0318	0.9682	92.19
26.5	474,860,436	19,430,063	0.0409	0.9591	89.26
27.5	449,707,026	7,714,729	0.0172	0.9828	85.61
28.5	413,248,992	21,405,799	0.0518	0.9482	84.14
29.5	373,595,795	15,310,191	0.0410	0.9590	79.78
30.5	287,721,173	11,293,735	0.0393	0.9607	76.51
31.5	252,028,433	6,111,298	0.0242	0.9758	73.50
32.5	147,293,552	3,359,040	0.0228	0.9772	71.72
33.5	138,879,725	2,286,504	0.0165	0.9835	70.08
34.5	133,296,280	2,998,437	0.0225	0.9775	68.92
35.5	123,361,400	326,332	0.0026	0.9974	67.37
36.5	101,541,819	3,519,594	0.0347	0.9653	67.19
37.5	94,964,393	1,705,632	0.0180	0.9820	64.86
38.5	59,997,866	5,384,122	0.0897	0.9103	63.69

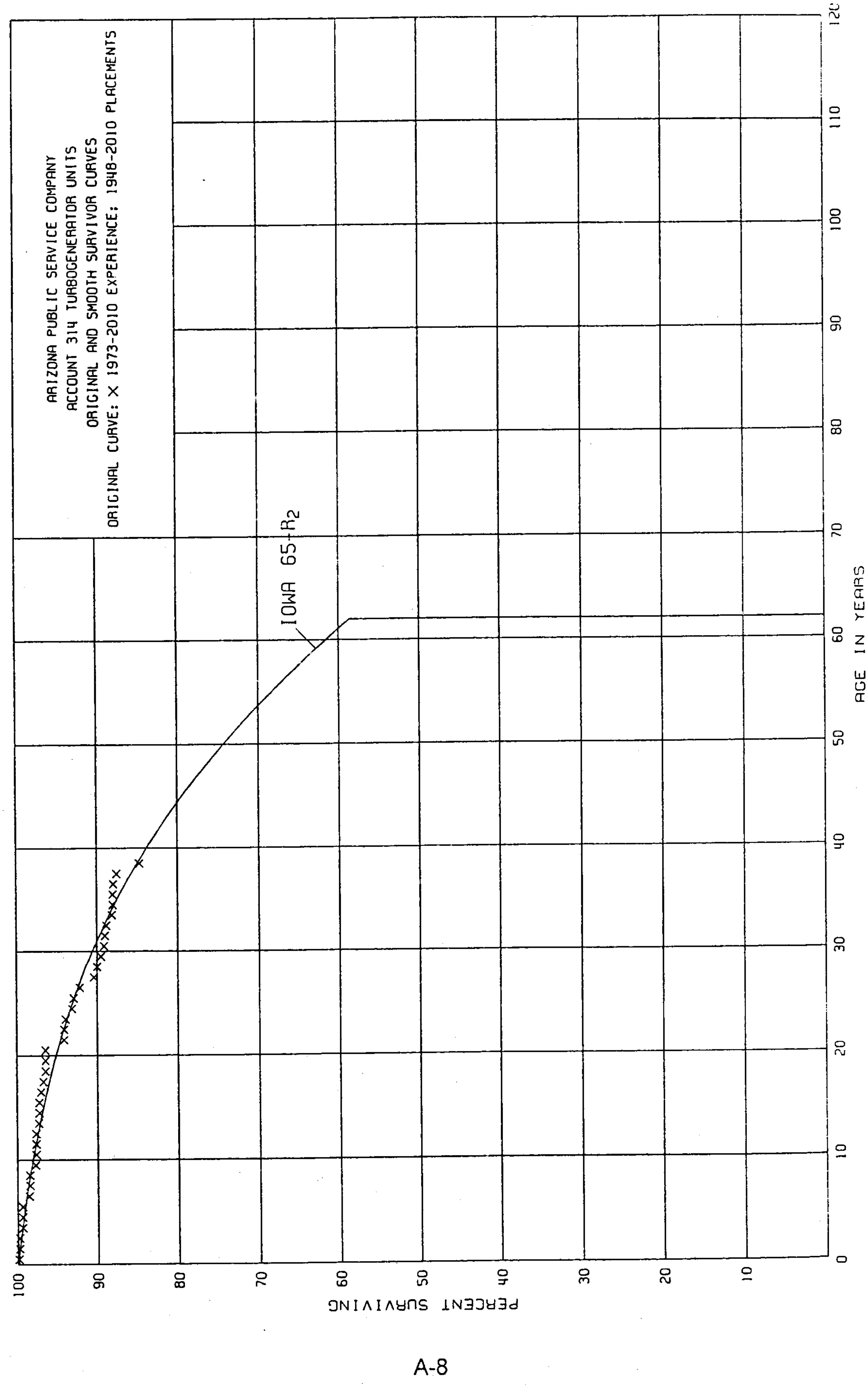
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1948-2010 EXPERIENCE BAND 1973-2010

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	52,075,477	945,200	0.0182	0.9818	57.98
40.5	46,843,946	2,174,586	0.0464	0.9536	56.92
41.5	44,338,970	7,284,201	0.1643	0.8357	54.28
42.5	36,969,714	5,141,544	0.1391	0.8609	45.36
43.5	31,546,163	6,954,345	0.2204	0.7796	39.05
44.5	24,520,417	1,472,413	0.0600	0.9400	30.44
45.5	22,803,053	3,957,811	0.1736	0.8264	28.61
46.5	18,583,091	2,107,205	0.1134	0.8866	23.64
47.5	16,383,101	1,090,721	0.0666	0.9334	20.96
48.5	17,534,072	695,007	0.0396	0.9604	19.56
49.5	16,676,308	206,958	0.0124	0.9876	18.79
50.5	9,100,587		0.0000	1.0000	18.56
51.5	8,663,255		0.0000	1.0000	18.56
52.5	8,652,514	112,324	0.0130	0.9870	18.56
53.5	9,883,017	107,644	0.0109	0.9891	18.32
54.5	9,774,927		0.0000	1.0000	18.12
55.5	5,789,384		0.0000	1.0000	18.12
56.5	3,691,039		0.0000	1.0000	18.12
57.5	1,343,859		0.0000	1.0000	18.12
58.5	1,343,859		0.0000	1.0000	18.12
59.5	1,343,859		0.0000	1.0000	18.12
60.5	1,343,859		0.0000	1.0000	18.12
61.5	1,343,859		0.0000	1.0000	18.12
62.5					18.12


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 314 TURBOGENERATOR UNITS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1973-2010 EXPERIENCE; 1948-2010 PLACEMENTS
IOWA 65-R2
AGE IN YEARS
PERCENT SURVIVING

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1948-2010 EXPERIENCE BAND 1973-2010

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	201,857,859	57,331	0.0003	0.9997	100.00
0.5	199,800,664	291,418	0.0015	0.9985	99.97
1.5	196,883,462		0.0000	1.0000	99.82
2.5	193,745,300	730,254	0.0038	0.9962	99.82
3.5	174,363,139		0.0000	1.0000	99.44
4.5	169,958,388		0.0000	1.0000	99.44
5.5	160,938,743	1,323,938	0.0082	0.9918	99.44
6.5	154,018,452	129,307	0.0008	0.9992	98.62
7.5	150,283,198		0.0000	1.0000	98.54
8.5	140,818,660	1,035,927	0.0074	0.9926	98.54
9.5	160,462,809	141,631	0.0009	0.9991	97.81
10.5	154,063,041	65,765	0.0004	0.9996	97.72
11.5	153,348,064		0.0000	1.0000	97.68
12.5	159,215,368	482,368	0.0030	0.9970	97.68
13.5	156,821,650	152,736	0.0010	0.9990	97.39
14.5	155,507,798		0.0000	1.0000	97.29
15.5	154,098,231	380,510	0.0025	0.9975	97.29
16.5	159,952,421	449,458	0.0028	0.9972	97.05
17.5	157,631,916	387,092	0.0025	0.9975	96.78
18.5	154,448,964	26,700	0.0002	0.9998	96.54
19.5	153,227,425	77,463	0.0005	0.9995	96.52
20.5	152,961,212	3,696,486	0.0242	0.9758	96.47
21.5	155,591,382	88,009	0.0006	0.9994	94.14
22.5	155,049,679	329,380	0.0021	0.9979	94.08
23.5	146,587,405	1,283,184	0.0088	0.9912	93.88
24.5	143,661,786	277,191	0.0019	0.9981	93.05
25.5	142,139,981	1,171,230	0.0082	0.9918	92.87
26.5	140,922,606	2,618,376	0.0186	0.9814	92.11
27.5	134,797,783	660,188	0.0049	0.9951	90.40
28.5	133,153,638	741,132	0.0056	0.9944	89.96
29.5	131,003,478	565,290	0.0043	0.9957	89.46
30.5	106,540,537	65,206	0.0006	0.9994	89.08
31.5	103,397,272	288,023	0.0028	0.9972	89.03
32.5	76,655,222	604,858	0.0079	0.9921	88.78
33.5	75,155,892	35,029	0.0005	0.9995	88.08
34.5	68,623,406	26,879	0.0004	0.9996	88.04
35.5	64,628,497	95,328	0.0015	0.9985	88.00
36.5	59,757,695	283,594	0.0047	0.9953	87.87
37.5	63,295,746	1,998,133	0.0316	0.9684	87.46
38.5	52,171,696	1,357,214	0.0260	0.9740	84.70

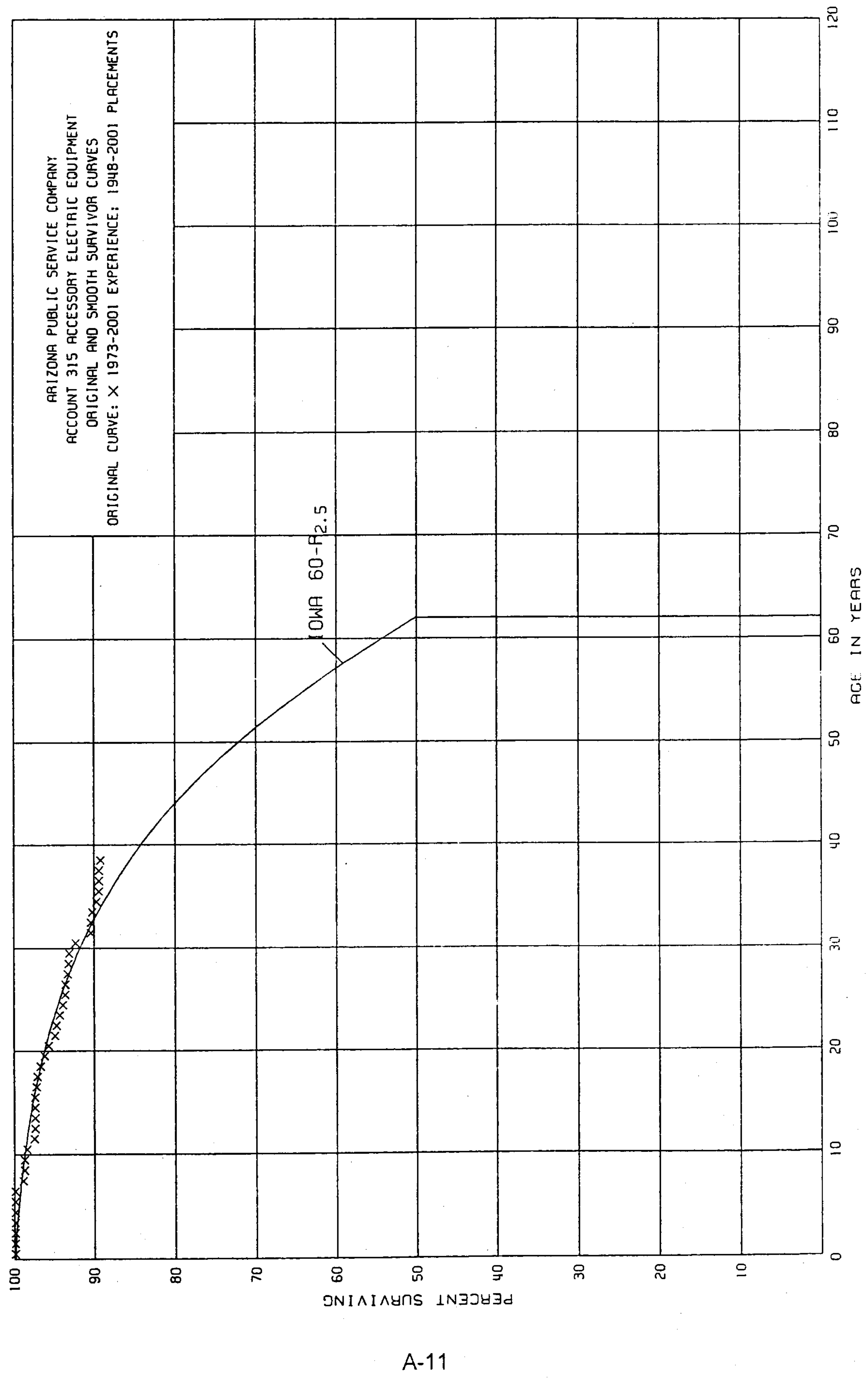
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1948-2010 EXPERIENCE BAND 1973-2010

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	44,257,195	357,480	0.0081	0.9919	82.50
40.5	39,233,254	1,043,496	0.0266	0.9734	81.83
41.5	36,816,410	631,674	0.0172	0.9828	79.65
42.5	36,105,586	304,751	0.0084	0.9916	78.28
43.5	35,792,172	1,307,991	0.0365	0.9635	77.62
44.5	34,467,772	2,021,046	0.0586	0.9414	74.79
45.5	32,446,725	174,389	0.0054	0.9946	70.41
46.5	32,271,768	246,419	0.0076	0.9924	70.03
47.5	16,447,165	418,281	0.0254	0.9746	69.50
48.5	14,889,520		0.0000	1.0000	67.73
49.5	14,881,860		0.0000	1.0000	67.73
50.5	6,089,384		0.0000	1.0000	67.73
51.5	5,889,857		0.0000	1.0000	67.73
52.5	5,889,857		0.0000	1.0000	67.73
53.5	7,339,700		0.0000	1.0000	67.73
54.5	7,339,700		0.0000	1.0000	67.73
55.5	3,517,601		0.0000	1.0000	67.73
56.5	3,517,601		0.0000	1.0000	67.73
57.5	1,449,843		0.0000	1.0000	67.73
58.5	1,449,843		0.0000	1.0000	67.73
59.5	1,449,843		0.0000	1.0000	67.73
60.5	1,449,843		0.0000	1.0000	67.73
61.5	1,449,843		0.0000	1.0000	67.73
62.5					67.73



ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1973-2001 EXPERIENCE; 1948-2001 PLACEMENTS
IOWA 60-R2.5
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1948-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	124,143,071		0.0000	1.0000	100.00
0.5	121,686,061	8,707	0.0001	0.9999	100.00
1.5	120,598,104		0.0000	1.0000	99.99
2.5	117,866,032		0.0000	1.0000	99.99
3.5	119,498,333		0.0000	1.0000	99.99
4.5	117,096,365	149,600	0.0013	0.9987	99.99
5.5	118,266,579		0.0000	1.0000	99.86
6.5	117,769,060	1,188,072	0.0101	0.9899	99.86
7.5	116,106,619	217,293	0.0019	0.9981	98.85
8.5	114,316,832	1,520	0.0000	1.0000	98.66
9.5	119,292,656	303,571	0.0025	0.9975	98.66
10.5	120,299,783	1,081,077	0.0090	0.9910	98.41
11.5	116,837,416	96,401	0.0008	0.9992	97.52
12.5	117,603,702	42,217	0.0004	0.9996	97.44
13.5	114,952,279		0.0000	1.0000	97.40
14.5	114,211,851	13,510	0.0001	0.9999	97.40
15.5	111,601,850	175,864	0.0016	0.9984	97.39
16.5	114,122,098	175,202	0.0015	0.9985	97.23
17.5	108,369,816	453,980	0.0042	0.9958	97.08
18.5	105,841,903	521,777	0.0049	0.9951	96.67
19.5	101,727,443	483,274	0.0048	0.9952	96.20
20.5	100,330,745	865,006	0.0086	0.9914	95.74
21.5	70,174,203	199,598	0.0028	0.9972	94.92
22.5	70,252,946	270,033	0.0038	0.9962	94.65
23.5	27,393,848	128,346	0.0047	0.9953	94.29
24.5	27,252,015	59,735	0.0022	0.9978	93.85
25.5	21,426,584		0.0000	1.0000	93.64
26.5	16,917,546	55,098	0.0033	0.9967	93.64
27.5	12,674,358	20,811	0.0016	0.9984	93.33
28.5	13,844,304	5,545	0.0004	0.9996	93.18
29.5	13,326,736	122,826	0.0092	0.9908	93.14
30.5	11,995,577	239,835	0.0200	0.9800	92.28
31.5	10,857,303		0.0000	1.0000	90.43
32.5	10,453,927	29,301	0.0028	0.9972	90.43
33.5	10,424,369	58,752	0.0056	0.9944	90.18
34.5	10,364,185	37,576	0.0036	0.9964	89.67
35.5	10,392,793		0.0000	1.0000	89.35
36.5	10,341,534		0.0000	1.0000	89.35
37.5	10,206,927	12,181	0.0012	0.9988	89.35
38.5	4,369,725	24,979	0.0057	0.9943	89.24

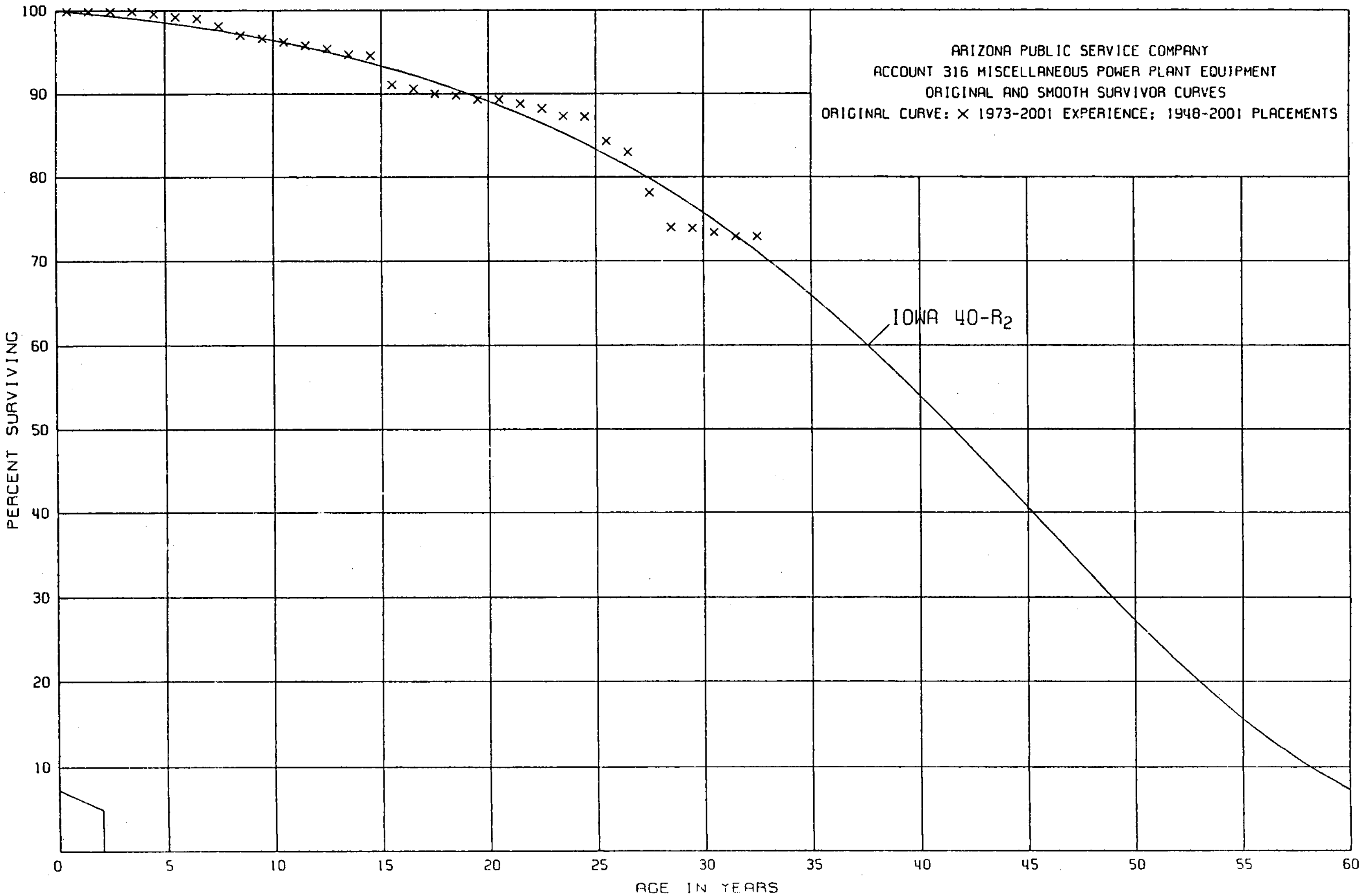
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1948-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,931,768		0.0000	1.0000	88.73
40.5	2,866,576		0.0000	1.0000	88.73
41.5	1,081,847		0.0000	1.0000	88.73
42.5	929,714		0.0000	1.0000	88.73
43.5	929,714		0.0000	1.0000	88.73
44.5	928,136		0.0000	1.0000	88.73
45.5	925,965		0.0000	1.0000	88.73
46.5	80,299		0.0000	1.0000	88.73
47.5					88.73


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1973-2001 EXPERIENCE; 1948-2001 PLACEMENTS
IOWA 40-R2
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30
35
40
45
50
55
60

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1948-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	48,112,496	17,788	0.0004	0.9996	100.00
0.5	45,741,322	4,017	0.0001	0.9999	99.96
1.5	43,625,481	6,497	0.0001	0.9999	99.95
2.5	42,830,177	31,226	0.0007	0.9993	99.94
3.5	42,111,271	106,167	0.0025	0.9975	99.87
4.5	37,485,362	156,501	0.0042	0.9958	99.62
5.5	33,780,504	80,425	0.0024	0.9976	99.20
6.5	32,027,956	283,487	0.0089	0.9911	98.96
7.5	29,186,219	336,634	0.0115	0.9885	98.08
8.5	28,324,981	105,183	0.0037	0.9963	96.95
9.5	28,034,939	124,804	0.0045	0.9955	96.59
10.5	27,159,074	108,165	0.0040	0.9960	96.16
11.5	25,106,726	99,631	0.0040	0.9960	95.78
12.5	24,860,428	183,119	0.0074	0.9926	95.40
13.5	22,361,538	13,649	0.0006	0.9994	94.69
14.5	21,406,844	804,765	0.0376	0.9624	94.63
15.5	18,524,975	103,244	0.0056	0.9944	91.07
16.5	17,103,171	103,248	0.0060	0.9940	90.56
17.5	15,476,667	43,887	0.0028	0.9972	90.02
18.5	14,040,006	67,244	0.0048	0.9952	89.77
19.5	13,450,922	7,487	0.0006	0.9994	89.34
20.5	12,583,288	65,805	0.0052	0.9948	89.29
21.5	9,663,156	67,581	0.0070	0.9930	88.83
22.5	8,666,370	94,651	0.0109	0.9891	88.21
23.5	4,745,866	785	0.0002	0.9998	87.25
24.5	4,263,012	145,990	0.0342	0.9658	87.23
25.5	3,147,677	46,658	0.0148	0.9852	84.25
26.5	2,212,335	131,636	0.0595	0.9405	83.00
27.5	1,392,799	71,797	0.0515	0.9485	78.06
28.5	1,268,223	3,348	0.0026	0.9974	74.04
29.5	1,105,393	7,366	0.0067	0.9933	73.85
30.5	1,082,472	7,000	0.0065	0.9935	73.36
31.5	721,256		0.0000	1.0000	72.88
32.5	724,490	46,735	0.0645	0.9355	72.88
33.5	676,568		0.0000	1.0000	68.18
34.5	677,057		0.0000	1.0000	68.18
35.5	720,150		0.0000	1.0000	68.18
36.5	664,483		0.0000	1.0000	68.18
37.5	747,762		0.0000	1.0000	68.18
38.5	586,114	3,804	0.0065	0.9935	68.18

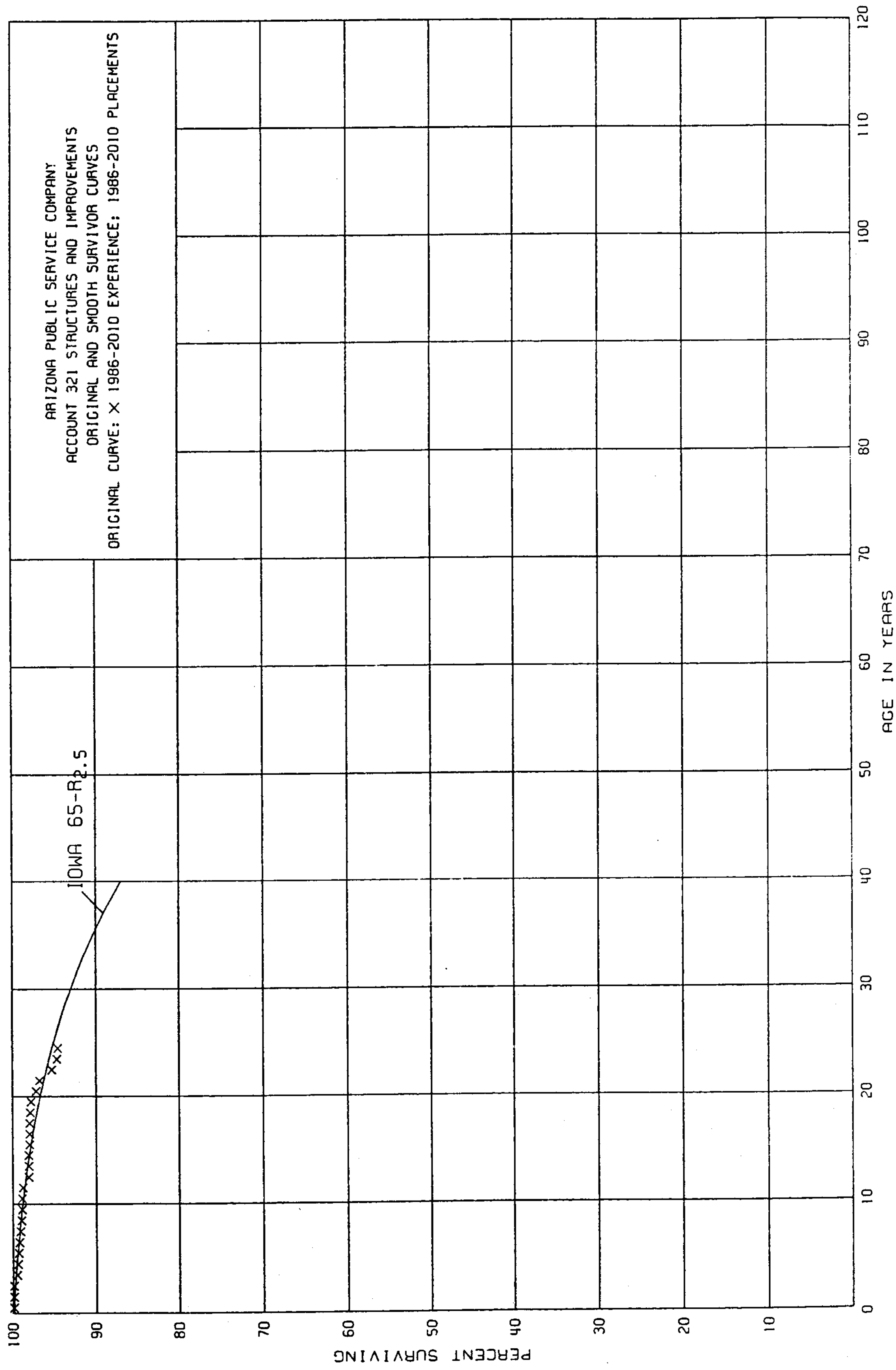
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1948-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	477,136		0.0000	1.0000	67.74
40.5	474,822		0.0000	1.0000	67.74
41.5	309,832		0.0000	1.0000	67.74
42.5	213,856		0.0000	1.0000	67.74
43.5	209,260		0.0000	1.0000	67.74
44.5	209,168		0.0000	1.0000	67.74
45.5	209,168		0.0000	1.0000	67.74
46.5	124,955		0.0000	1.0000	67.74
47.5					67.74


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 321 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1986-2010 EXPERIENCE; 1986-2010 PLACEMENTS
IOWA 65-R2.5
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120

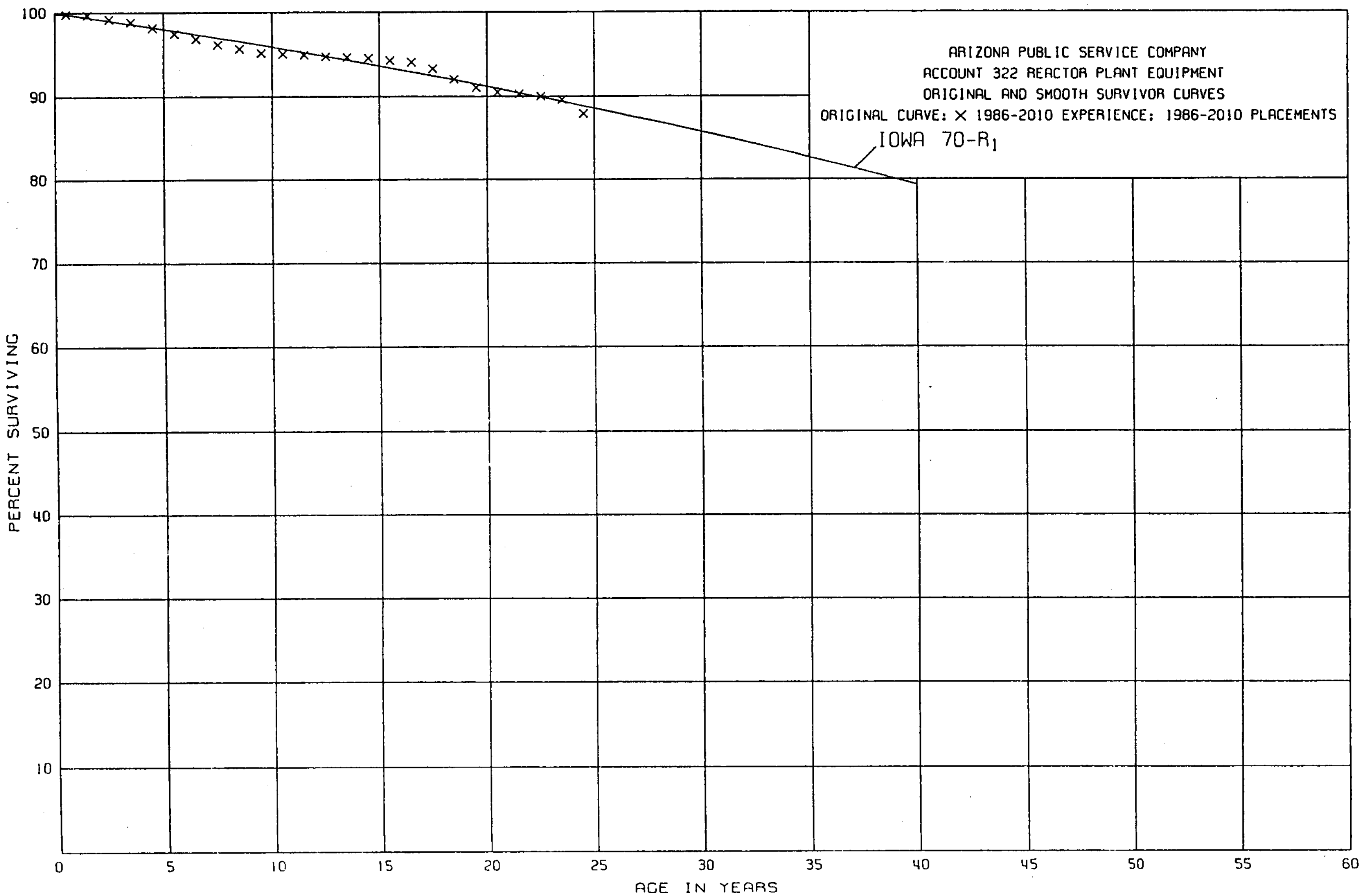
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 321 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1986-2010 EXPERIENCE BAND 1986-2010

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	703,079,376		0.0000	1.0000	100.00
0.5	702,550,638		0.0000	1.0000	100.00
1.5	699,985,201	223,596	0.0003	0.9997	100.00
2.5	690,967,578	3,554,478	0.0051	0.9949	99.97
3.5	674,357,133	425,337	0.0006	0.9994	99.46
4.5	670,191,187	460,893	0.0007	0.9993	99.40
5.5	640,517,033	613,560	0.0010	0.9990	99.33
6.5	639,426,465	968,087	0.0015	0.9985	99.23
7.5	638,424,360	710,599	0.0011	0.9989	99.08
8.5	630,597,016	160,432	0.0003	0.9997	98.97
9.5	630,237,976	377,498	0.0006	0.9994	98.94
10.5	627,247,829	444,455	0.0007	0.9993	98.88
11.5	625,484,732	4,279,510	0.0068	0.9932	98.81
12.5	620,397,023	369,142	0.0006	0.9994	98.14
13.5	614,676,096	146,354	0.0002	0.9998	98.08
14.5	610,900,136	182,634	0.0003	0.9997	98.06
15.5	609,070,841		0.0000	1.0000	98.03
16.5	608,540,587	437,915	0.0007	0.9993	98.03
17.5	606,991,892	475,451	0.0008	0.9992	97.96
18.5	599,319,520	702,628	0.0012	0.9988	97.88
19.5	587,596,380	3,423,105	0.0058	0.9942	97.76
20.5	573,477,389	2,466,232	0.0043	0.9957	97.19
21.5	569,564,999	8,793,253	0.0154	0.9846	96.77
22.5	403,689,271	2,395,142	0.0059	0.9941	95.28
23.5	400,783,617	333,528	0.0008	0.9992	94.72
24.5					94.64


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 322 REACTOR PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1986-2010 EXPERIENCE: 1986-2010 PLACEMENTS
IOWA 70-R1
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30
35
40
45
50
55
60

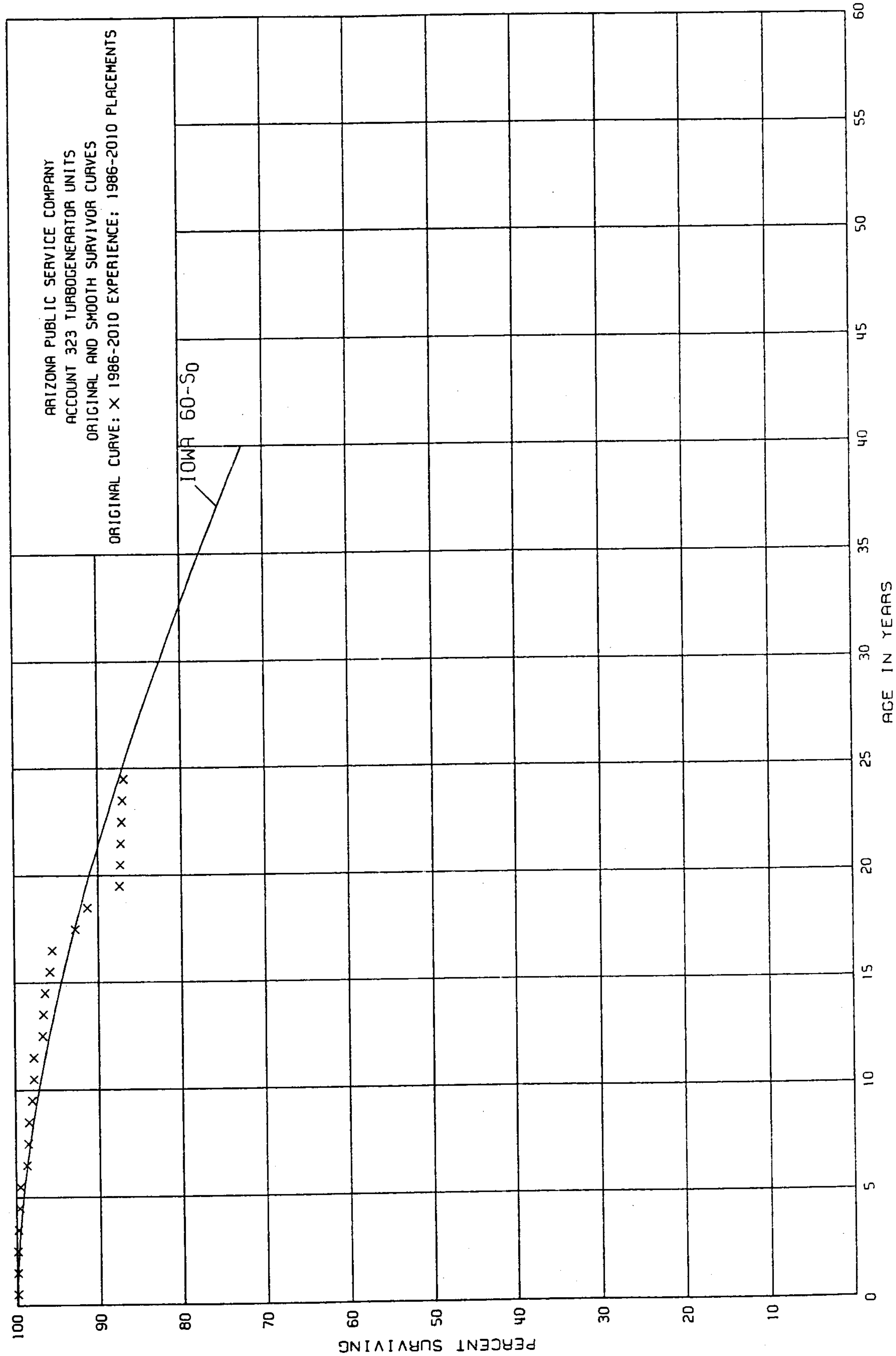
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 322 REACTOR PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1986-2010 EXPERIENCE BAND 1986-2010

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,325,368,817	2,972,537	0.0022	0.9978	100.00
0.5	1,312,766,297	589,326	0.0004	0.9996	99.78
1.5	1,302,947,791	7,694,226	0.0059	0.9941	99.74
2.5	1,284,932,391	2,787,524	0.0022	0.9978	99.15
3.5	1,223,967,265	9,233,971	0.0075	0.9925	98.93
4.5	1,184,285,030	8,920,739	0.0075	0.9925	98.19
5.5	999,805,857	6,200,375	0.0062	0.9938	97.45
6.5	946,361,820	6,177,120	0.0065	0.9935	96.85
7.5	907,877,297	5,147,092	0.0057	0.9943	96.22
8.5	899,441,714	4,665,644	0.0052	0.9948	95.67
9.5	893,228,100	616,047	0.0007	0.9993	95.17
10.5	892,583,781	1,263,402	0.0014	0.9986	95.10
11.5	888,583,886	1,704,828	0.0019	0.9981	94.97
12.5	883,901,040	1,248,044	0.0014	0.9986	94.79
13.5	880,691,322	250,854	0.0003	0.9997	94.66
14.5	877,071,293	3,178,246	0.0036	0.9964	94.63
15.5	866,436,482	1,574,341	0.0018	0.9982	94.29
16.5	862,683,169	7,845,978	0.0091	0.9909	94.12
17.5	850,038,187	11,485,437	0.0135	0.9865	93.26
18.5	821,242,291	9,093,081	0.0111	0.9889	92.00
19.5	809,214,412	3,986,114	0.0049	0.9951	90.98
20.5	805,113,711	2,516,409	0.0031	0.9969	90.53
21.5	801,451,629	2,132,304	0.0027	0.9973	90.25
22.5	483,374,415	2,307,558	0.0048	0.9952	90.01
23.5	476,424,622	8,754,570	0.0184	0.9816	89.58
24.5					87.93


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 323 TURBOGENERATOR UNITS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1986-2010 EXPERIENCE: 1986-2010 PLACEMENTS
IOWA 60-S0
PERCENT SURVIVING
AGE IN YEARS

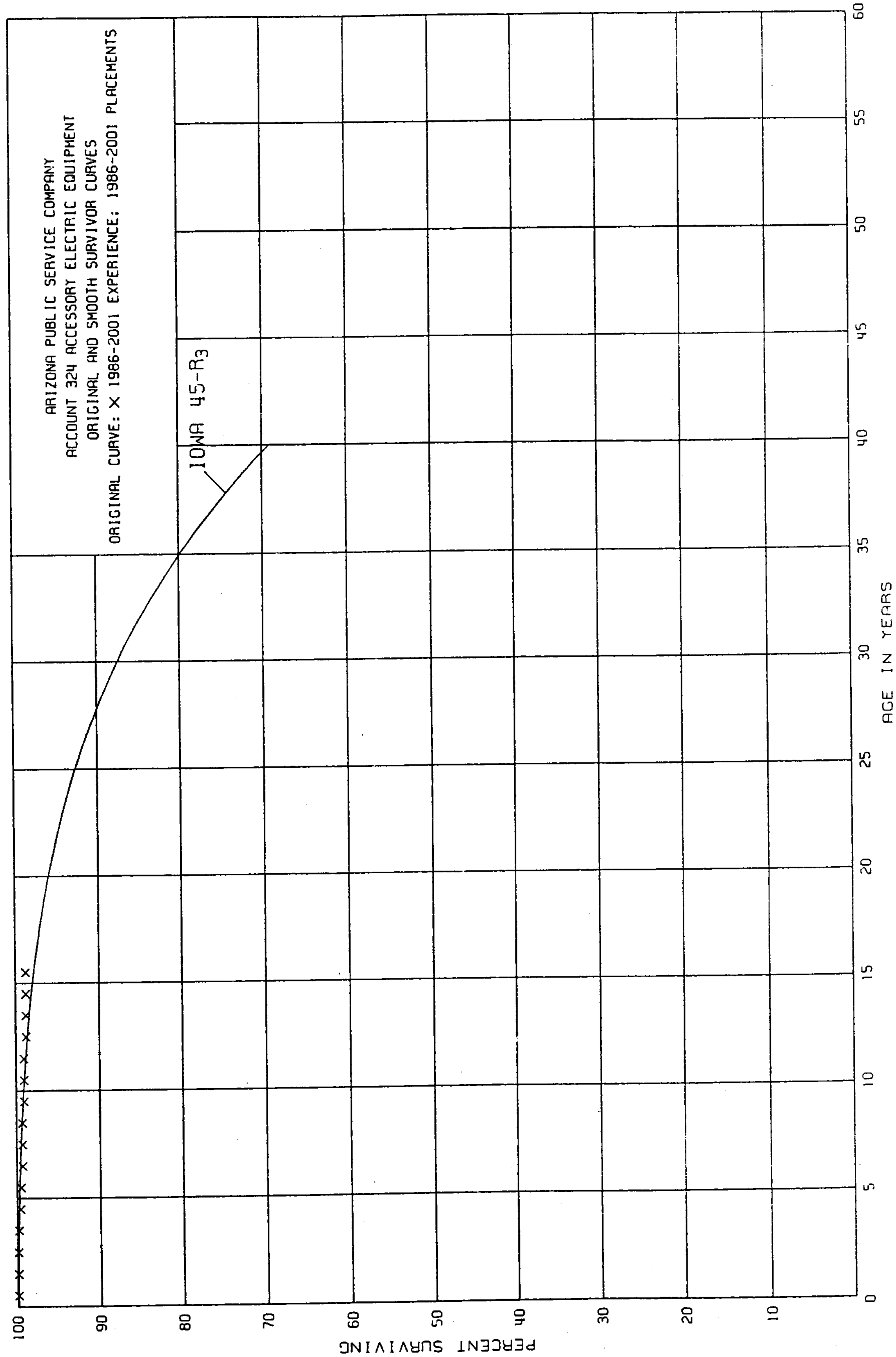
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 323 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1986-2010 EXPERIENCE BAND 1986-2010

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	404,584,934		0.0000	1.0000	100.00
0.5	404,301,966		0.0000	1.0000	100.00
1.5	403,898,737	456,603	0.0011	0.9989	100.00
2.5	403,175,664	502,365	0.0012	0.9988	99.89
3.5	386,960,853	496,096	0.0013	0.9987	99.77
4.5	383,444,116	577,348	0.0015	0.9985	99.64
5.5	362,760,998	3,038,210	0.0084	0.9916	99.49
6.5	356,926,804	415,411	0.0012	0.9988	98.65
7.5	347,552,376	396,505	0.0011	0.9989	98.53
8.5	346,177,292	1,530,186	0.0044	0.9956	98.42
9.5	344,221,710	645,707	0.0019	0.9981	97.99
10.5	340,710,952	52,575	0.0002	0.9998	97.80
11.5	337,670,179	3,698,788	0.0110	0.9890	97.78
12.5	333,390,580	542,686	0.0016	0.9984	96.70
13.5	330,726,166	678,341	0.0021	0.9979	96.55
14.5	329,439,773	1,866,052	0.0057	0.9943	96.35
15.5	326,447,380	1,088,717	0.0033	0.9967	95.80
16.5	322,843,958	9,501,826	0.0294	0.9706	95.48
17.5	311,197,072	4,784,441	0.0154	0.9846	92.67
18.5	305,177,724	12,754,647	0.0418	0.9582	91.24
19.5	290,071,976	413,901	0.0014	0.9986	87.43
20.5	289,261,660	266,491	0.0009	0.9991	87.31
21.5	288,360,365	412,966	0.0014	0.9986	87.23
22.5	163,549,517	266,491	0.0016	0.9984	87.11
23.5	163,283,026	266,491	0.0016	0.9984	86.97
24.5					86.83


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 324 ACCESSORY ELECTRIC EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1986-2001 EXPERIENCE; 1986-2001 PLACEMENTS
IOWA 45-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30
35
40
45
50
55
60

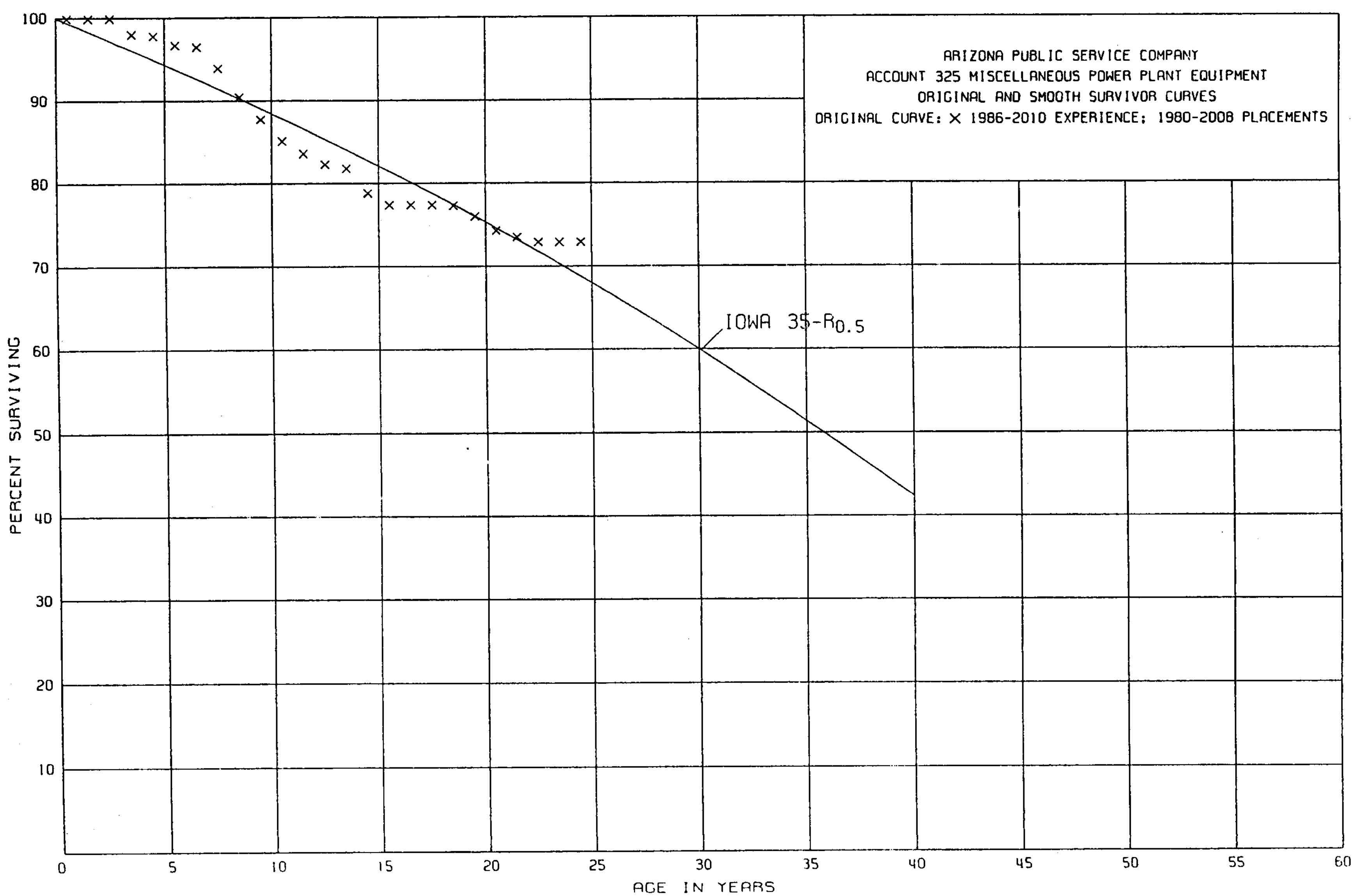
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 324 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1986-2001 EXPERIENCE BAND 1986-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	293,812,372	3,238	0.0000	1.0000	100.00
0.5	293,296,876	13,787	0.0000	1.0000	100.00
1.5	293,781,908	293,722	0.0010	0.9990	100.00
2.5	292,717,107	414,957	0.0014	0.9986	99.90
3.5	285,903,610	581,274	0.0020	0.9980	99.76
4.5	283,426,968	134,936	0.0005	0.9995	99.56
5.5	271,048,398	544,252	0.0020	0.9980	99.51
6.5	269,869,637	113,095	0.0004	0.9996	99.31
7.5	269,516,425	56,025	0.0002	0.9998	99.27
8.5	264,521,133	296,956	0.0011	0.9989	99.25
9.5	263,134,814	57,117	0.0002	0.9998	99.14
10.5	261,745,174	859	0.0000	1.0000	99.12
11.5	261,606,609	726,377	0.0028	0.9972	99.12
12.5	260,757,954	1,252	0.0000	1.0000	98.84
13.5	172,668,645		0.0000	1.0000	98.84
14.5	133,074,496		0.0000	1.0000	98.84
15.5					98.84



ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 325 MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1986-2010 EXPERIENCE; 1980-2008 PLACEMENTS
IOWA 35-R0.5
PERCENT SURVIVING
AGE IN YEARS

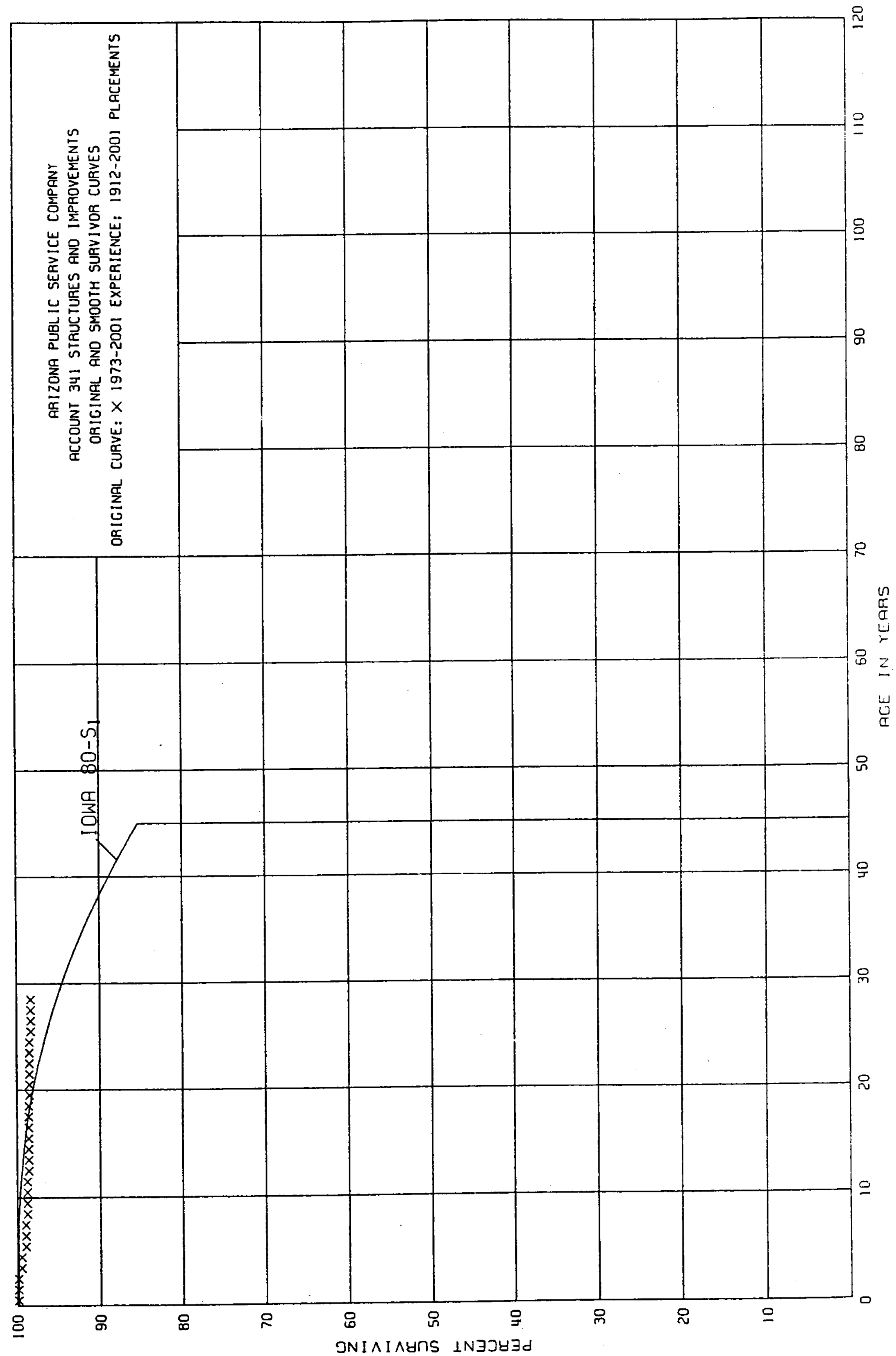
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 325 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1980-2008 EXPERIENCE BAND 1986-2010

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	180,162,624	34,412	0.0002	0.9998	100.00
0.5	182,092,250		0.0000	1.0000	99.98
1.5	179,978,639	72,367	0.0004	0.9996	99.98
2.5	179,419,177	3,474,224	0.0194	0.9806	99.94
3.5	173,342,954	395,347	0.0023	0.9977	98.00
4.5	170,284,065	1,936,993	0.0114	0.9886	97.77
5.5	162,279,507	255,698	0.0016	0.9984	96.66
6.5	161,870,388	4,378,924	0.0271	0.9729	96.51
7.5	159,107,055	5,842,118	0.0367	0.9633	93.89
8.5	153,110,842	4,691,560	0.0306	0.9694	90.44
9.5	148,319,993	4,349,592	0.0293	0.9707	87.67
10.5	143,219,831	2,481,033	0.0173	0.9827	85.10
11.5	139,323,262	2,192,479	0.0157	0.9843	83.63
12.5	136,881,832	816,764	0.0060	0.9940	82.32
13.5	135,374,931	5,041,070	0.0372	0.9628	81.83
14.5	128,222,368	2,236,620	0.0174	0.9826	78.79
15.5	116,052,642	16,339	0.0001	0.9999	77.42
16.5	100,687,341		0.0000	1.0000	77.41
17.5	97,053,668	126,583	0.0013	0.9987	77.41
18.5	93,674,953	1,628,525	0.0174	0.9826	77.31
19.5	89,248,723	1,981,626	0.0222	0.9778	75.96
20.5	77,749,753	839,446	0.0108	0.9892	74.27
21.5	74,744,421	572,955	0.0077	0.9923	73.47
22.5	47,673,138		0.0000	1.0000	72.90
23.5	47,605,013		0.0000	1.0000	72.90
24.5					72.90


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 341 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1973-2001 EXPERIENCE; 1912-2001 PLACEMENTS
IOWA 80-S1
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

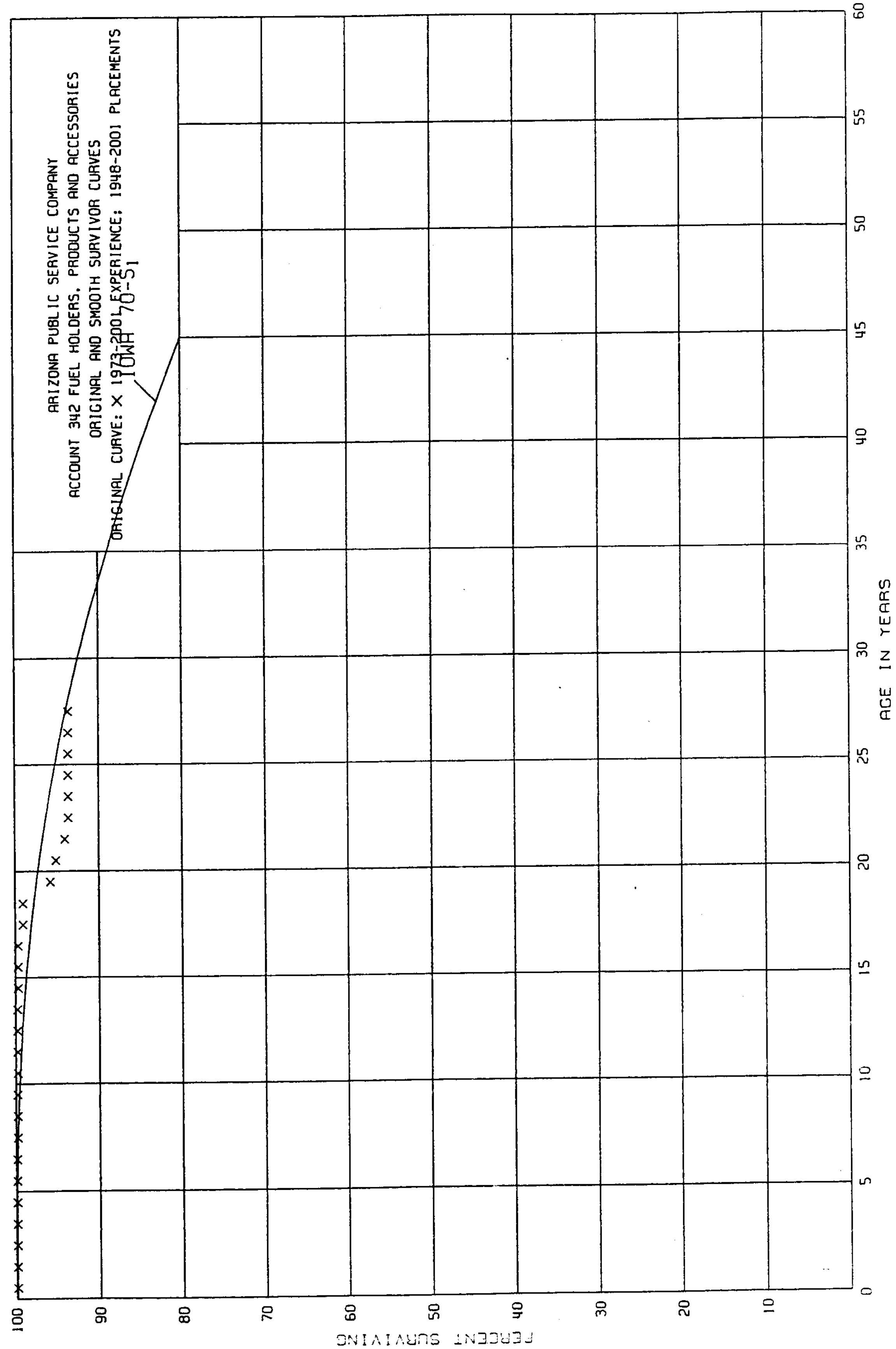
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1912-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,446,284		0.0000	1.0000	100.00
0.5	5,806,699		0.0000	1.0000	100.00
1.5	7,712,615		0.0000	1.0000	100.00
2.5	7,814,706	36,797	0.0047	0.9953	100.00
3.5	7,621,114		0.0000	1.0000	99.53
4.5	7,565,413	38,826	0.0051	0.9949	99.53
5.5	7,323,190		0.0000	1.0000	99.02
6.5	7,216,099	900	0.0001	0.9999	99.02
7.5	7,080,537	14,269	0.0020	0.9980	99.01
8.5	7,058,319	3	0.0000	1.0000	98.81
9.5	7,023,352		0.0000	1.0000	98.81
10.5	7,078,559		0.0000	1.0000	98.81
11.5	6,971,239	12,750	0.0018	0.9982	98.81
12.5	6,936,151		0.0000	1.0000	98.63
13.5	6,999,249		0.0000	1.0000	98.63
14.5	6,539,896		0.0000	1.0000	98.63
15.5	6,562,272		0.0000	1.0000	98.63
16.5	6,109,413		0.0000	1.0000	98.63
17.5	5,940,932		0.0000	1.0000	98.63
18.5	3,740,322	4,000	0.0011	0.9989	98.63
19.5	3,906,779		0.0000	1.0000	98.52
20.5	3,884,068		0.0000	1.0000	98.52
21.5	3,884,068		0.0000	1.0000	98.52
22.5	3,960,703		0.0000	1.0000	98.52
23.5	3,938,327		0.0000	1.0000	98.52
24.5	3,935,384	10,450	0.0027	0.9973	98.52
25.5	1,160,356		0.0000	1.0000	98.25
26.5	1,095,004		0.0000	1.0000	98.25
27.5	955,256		0.0000	1.0000	98.25
28.5	113,078		0.0000	1.0000	98.25
29.5	79,986		0.0000	1.0000	98.25
30.5	17,431		0.0000	1.0000	98.25
31.5	17,431		0.0000	1.0000	98.25
32.5	17,431		0.0000	1.0000	98.25
33.5	17,431		0.0000	1.0000	98.25
34.5	17,431		0.0000	1.0000	98.25
35.5	17,431		0.0000	1.0000	98.25
36.5	17,431		0.0000	1.0000	98.25
37.5	17,431		0.0000	1.0000	98.25
38.5					98.25


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 342 FUEL HOLDERS, PRODUCTS AND ACCESSORIES
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1973-2001 EXPERIENCE; 1948-2001 PLACEMENTS
IOWA 70-S1
AGE IN YEARS
PERCENT SURVIVING
0
5
10
15
20
25
30
35
40
45
50
55
60
100
90
80
70
60
50
40
30
20
10

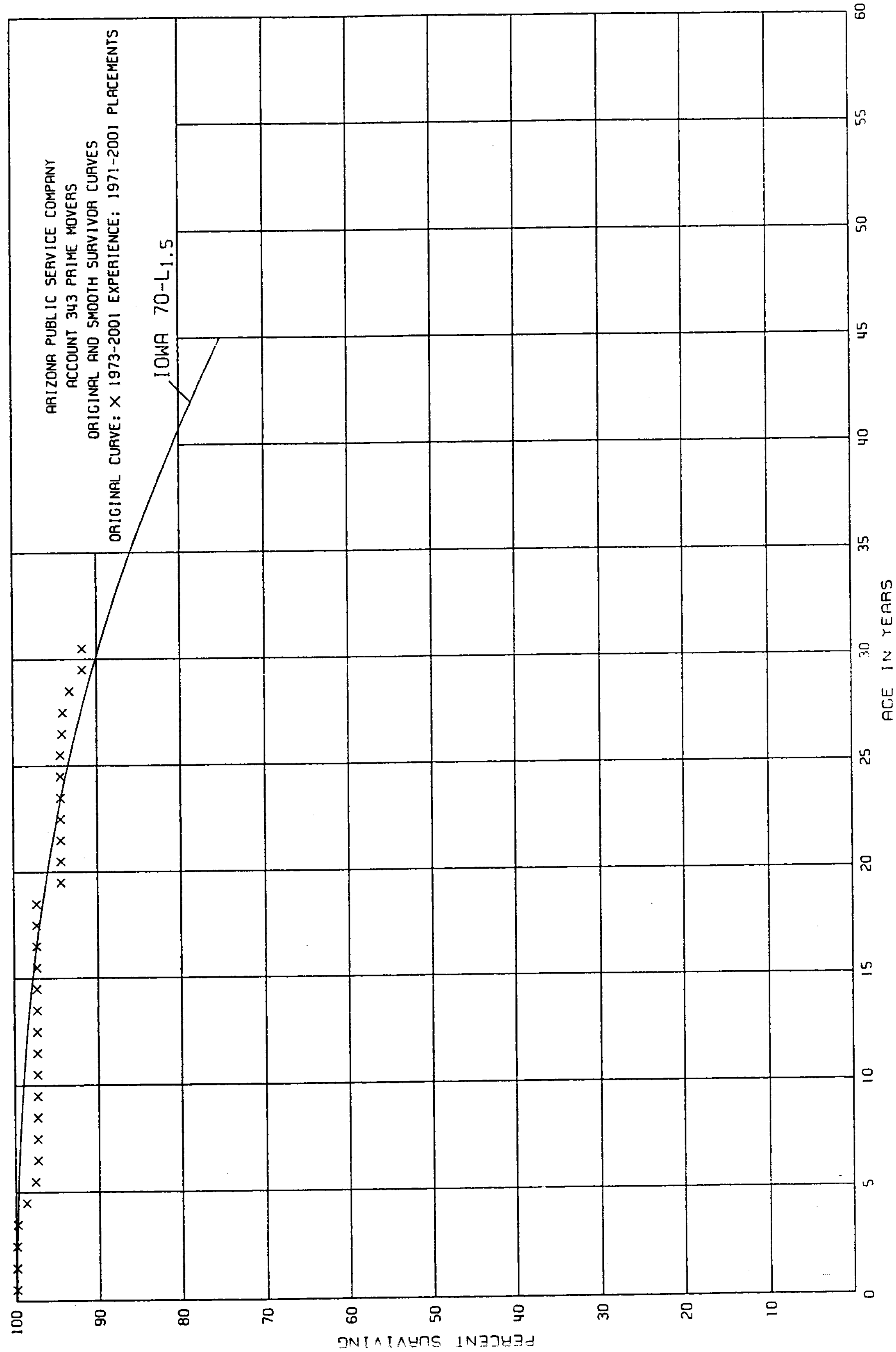
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 342 FUEL HOLDERS, PRODUCTS AND ACCESSORIES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1948-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	34,364,178	10,580	0.0003	0.9997	100.00
0.5	34,372,819	7,730	0.0002	0.9998	99.97
1.5	23,380,021		0.0000	1.0000	99.95
2.5	23,380,021		0.0000	1.0000	99.95
3.5	23,364,907		0.0000	1.0000	99.95
4.5	23,364,907		0.0000	1.0000	99.95
5.5	23,364,907		0.0000	1.0000	99.95
6.5	23,364,907	38,502	0.0016	0.9984	99.95
7.5	23,326,405		0.0000	1.0000	99.79
8.5	22,747,576		0.0000	1.0000	99.79
9.5	22,478,323		0.0000	1.0000	99.79
10.5	21,557,839		0.0000	1.0000	99.79
11.5	21,046,344		0.0000	1.0000	99.79
12.5	21,033,385		0.0000	1.0000	99.79
13.5	21,192,516	18,490	0.0009	0.9991	99.79
14.5	21,059,512		0.0000	1.0000	99.70
15.5	20,945,984		0.0000	1.0000	99.70
16.5	20,357,697	128,050	0.0063	0.9937	99.70
17.5	20,229,647		0.0000	1.0000	99.07
18.5	6,446,620	214,196	0.0332	0.9668	99.07
19.5	6,230,448	42,920	0.0069	0.9931	95.78
20.5	6,253,453	76,587	0.0122	0.9878	95.12
21.5	6,176,866	22,874	0.0037	0.9963	93.96
22.5	6,132,548		0.0000	1.0000	93.61
23.5	6,123,824		0.0000	1.0000	93.61
24.5	5,690,981		0.0000	1.0000	93.61
25.5	5,133,524		0.0000	1.0000	93.61
26.5	5,121,535		0.0000	1.0000	93.61
27.5	876,630		0.0000	1.0000	93.61
28.5	575,404		0.0000	1.0000	93.61
29.5	118,702		0.0000	1.0000	93.61
30.5					93.61


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 343 PRIME MOVERS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1973-2001 EXPERIENCE; 1971-2001 PLACEMENTS
IOWA 70-L1.5
PERCENT SURVIVING
AGE IN YEARS

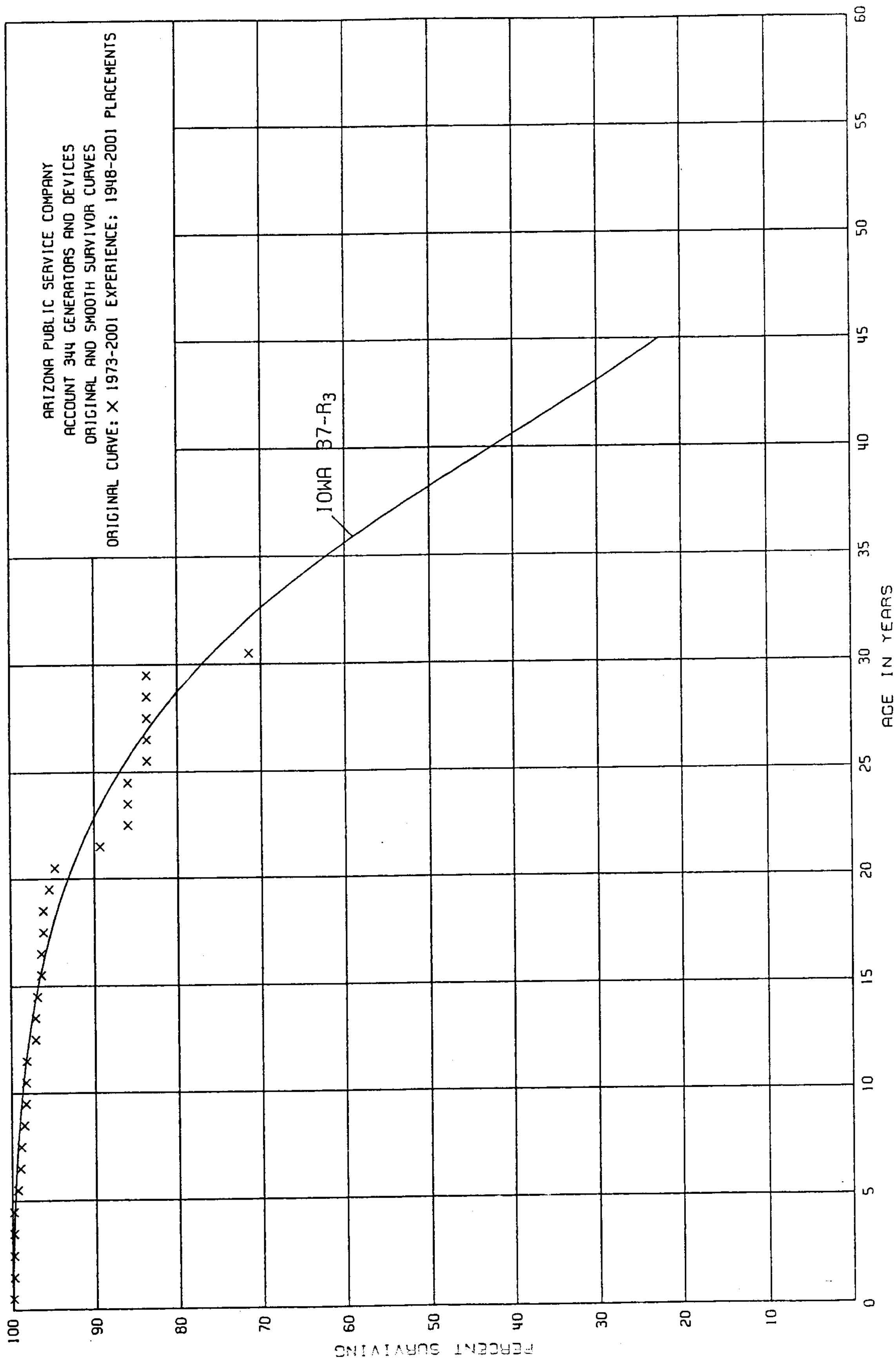
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 343 PRIME MOVERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1971-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	25,916,210		0.0000	1.0000	100.00
0.5	30,379,686		0.0000	1.0000	100.00
1.5	32,036,607		0.0000	1.0000	100.00
2.5	31,628,864	72,000	0.0023	0.9977	100.00
3.5	32,290,580	348,806	0.0108	0.9892	99.77
4.5	31,941,774	364,918	0.0114	0.9886	98.69
5.5	31,576,856	88,373	0.0028	0.9972	97.56
6.5	31,488,483		0.0000	1.0000	97.29
7.5	31,488,483		0.0000	1.0000	97.29
8.5	35,349,716		0.0000	1.0000	97.29
9.5	34,517,628		0.0000	1.0000	97.29
10.5	34,371,729		0.0000	1.0000	97.29
11.5	34,371,729		0.0000	1.0000	97.29
12.5	34,371,729		0.0000	1.0000	97.29
13.5	29,969,328		0.0000	1.0000	97.29
14.5	29,947,073		0.0000	1.0000	97.29
15.5	29,849,711		0.0000	1.0000	97.29
16.5	29,864,641		0.0000	1.0000	97.29
17.5	29,886,896		0.0000	1.0000	97.29
18.5	26,213,376	800,930	0.0306	0.9694	97.29
19.5	24,569,787		0.0000	1.0000	94.31
20.5	28,170,301		0.0000	1.0000	94.31
21.5	28,170,301		0.0000	1.0000	94.31
22.5	27,675,539		0.0000	1.0000	94.31
23.5	27,111,447		0.0000	1.0000	94.31
24.5	27,111,447		0.0000	1.0000	94.31
25.5	26,889,989	48,714	0.0018	0.9982	94.31
26.5	26,841,275	47,747	0.0018	0.9982	94.14
27.5	23,701,812	185,403	0.0078	0.9922	93.97
28.5	11,188,881	182,106	0.0163	0.9837	93.24
29.5	2,047,458		0.0000	1.0000	91.72
30.5					91.72


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 344 GENERATORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1973-2001 EXPERIENCE; 1948-2001 PLACEMENTS
IOWA 37-R3
AGE IN YEARS
PERCENT SURVIVING
0
5
10
15
20
25
30
35
40
45
50
55
60
100
90
80
70
60
50
40
30
20
10

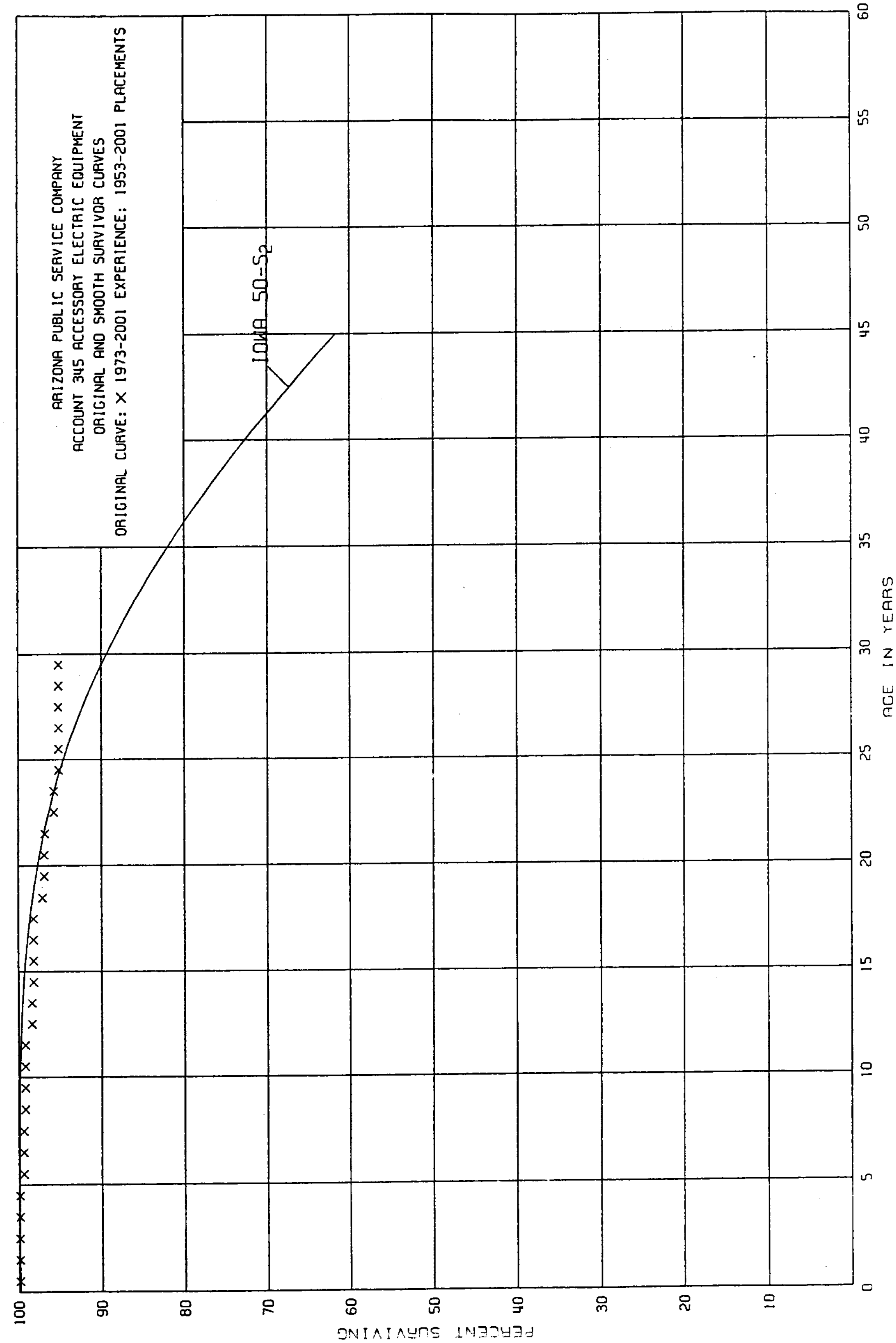
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 344 GENERATORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1948-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	147,630,778		0.0000	1.0000	100.00
0.5	142,144,778	224,378	0.0016	0.9984	100.00
1.5	84,165,679		0.0000	1.0000	99.84
2.5	82,519,784		0.0000	1.0000	99.84
3.5	77,448,273	5,089	0.0001	0.9999	99.84
4.5	76,549,374	412,547	0.0054	0.9946	99.83
5.5	75,212,689	225,488	0.0030	0.9970	99.29
6.5	74,305,905	103,849	0.0014	0.9986	98.99
7.5	73,905,567	235,355	0.0032	0.9968	98.85
8.5	69,660,907	133,000	0.0019	0.9981	98.53
9.5	67,289,889	34,385	0.0005	0.9995	98.34
10.5	67,210,858	66,889	0.0010	0.9990	98.29
11.5	66,635,811	729,035	0.0109	0.9891	98.19
12.5	64,694,601		0.0000	1.0000	97.12
13.5	63,457,791	158,236	0.0025	0.9975	97.12
14.5	62,952,817	296,240	0.0047	0.9953	96.88
15.5	62,656,577		0.0000	1.0000	96.42
16.5	62,270,857	238,050	0.0038	0.9962	96.42
17.5	62,150,552		0.0000	1.0000	96.05
18.5	11,642,542	79,167	0.0068	0.9932	96.05
19.5	11,560,851	91,057	0.0079	0.9921	95.40
20.5	12,243,408	687,969	0.0562	0.9438	94.65
21.5	11,555,439	436,512	0.0378	0.9622	89.33
22.5	11,115,941		0.0000	1.0000	85.95
23.5	11,108,240		0.0000	1.0000	85.95
24.5	11,105,909	295,240	0.0266	0.9734	85.95
25.5	9,013,222		0.0000	1.0000	83.66
26.5	9,013,222		0.0000	1.0000	83.66
27.5	7,451,023		0.0000	1.0000	83.66
28.5	4,296,254		0.0000	1.0000	83.66
29.5	1,071,486	157,000	0.1465	0.8535	83.66
30.5					71.40



ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1973-2001 EXPERIENCE; 1953-2001 PLACEMENTS
IOWA 50-S2
PERCENT SURVIVING
AGE IN YEARS

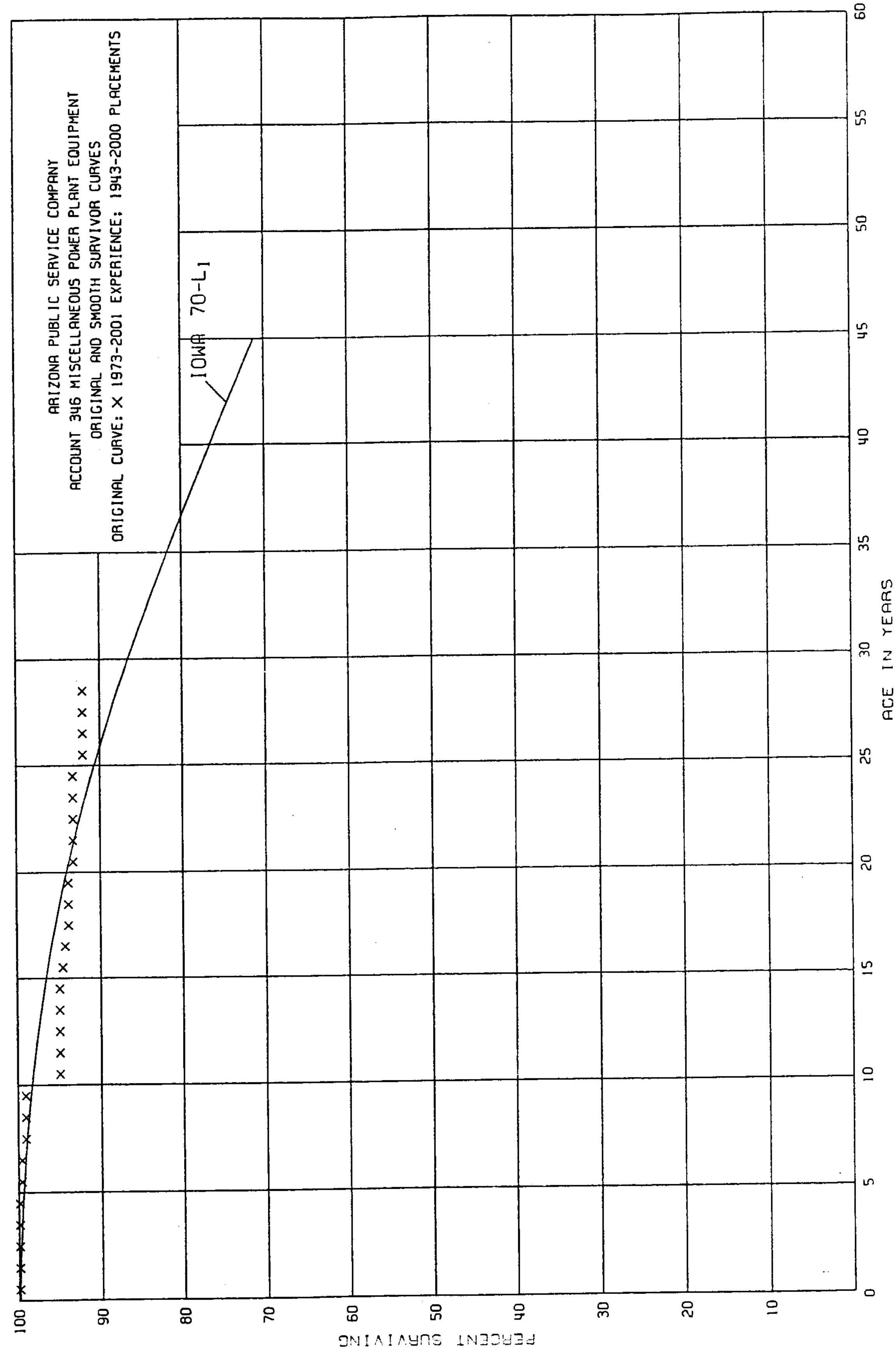
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1953-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	16,611,750		0.0000	1.0000	100.00
0.5	19,215,050		0.0000	1.0000	100.00
1.5	15,472,594		0.0000	1.0000	100.00
2.5	15,323,740		0.0000	1.0000	100.00
3.5	14,920,801		0.0000	1.0000	100.00
4.5	14,909,451	96,512	0.0065	0.9935	100.00
5.5	14,683,344		0.0000	1.0000	99.35
6.5	14,590,672		0.0000	1.0000	99.35
7.5	14,228,304	15,873	0.0011	0.9989	99.35
8.5	14,059,953		0.0000	1.0000	99.24
9.5	13,836,653		0.0000	1.0000	99.24
10.5	13,809,719		0.0000	1.0000	99.24
11.5	13,518,344	120,000	0.0089	0.9911	99.24
12.5	13,282,108		0.0000	1.0000	98.36
13.5	13,198,376	15,453	0.0012	0.9988	98.36
14.5	13,139,855		0.0000	1.0000	98.24
15.5	13,124,301		0.0000	1.0000	98.24
16.5	12,773,654		0.0000	1.0000	98.24
17.5	12,422,145	139,766	0.0113	0.9887	98.24
18.5	7,192,046	14,468	0.0020	0.9980	97.13
19.5	7,063,072		0.0000	1.0000	96.94
20.5	7,881,638	16,124	0.0020	0.9980	96.94
21.5	7,860,012	85,769	0.0109	0.9891	96.75
22.5	7,774,243		0.0000	1.0000	95.70
23.5	7,774,243	53,090	0.0068	0.9932	95.70
24.5	7,718,269		0.0000	1.0000	95.05
25.5	5,415,172		0.0000	1.0000	95.05
26.5	5,409,643		0.0000	1.0000	95.05
27.5	4,924,802		0.0000	1.0000	95.05
28.5	3,209,095		0.0000	1.0000	95.05
29.5	614,123		0.0000	1.0000	95.05
30.5					95.05


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1973-2001 EXPERIENCE; 1943-2000 PLACEMENTS
IOWA 70-L1
PERCENT SURVIVING
AGE IN YEARS

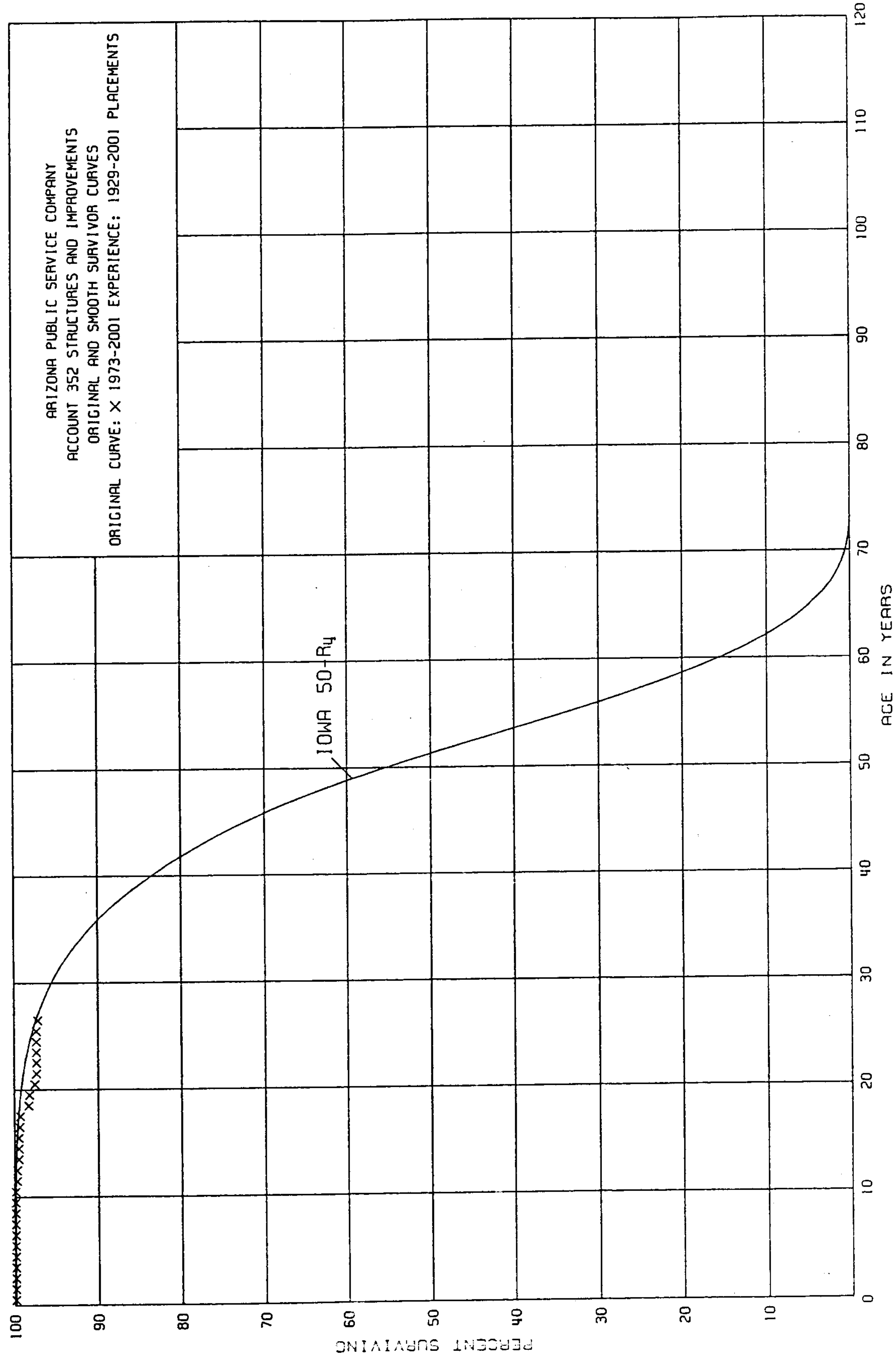
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1943-2000 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,713,150		0.0000	1.0000	100.00
0.5	5,828,344		0.0000	1.0000	100.00
1.5	4,949,355		0.0000	1.0000	100.00
2.5	4,911,576		0.0000	1.0000	100.00
3.5	4,838,833		0.0000	1.0000	100.00
4.5	4,809,776	20,473	0.0043	0.9957	100.00
5.5	4,779,060		0.0000	1.0000	99.57
6.5	4,778,528	25,000	0.0052	0.9948	99.57
7.5	4,400,351		0.0000	1.0000	99.05
8.5	2,824,725		0.0000	1.0000	99.05
9.5	2,779,889	115,715	0.0416	0.9584	99.05
10.5	2,578,508		0.0000	1.0000	94.93
11.5	2,681,516		0.0000	1.0000	94.93
12.5	2,600,934		0.0000	1.0000	94.93
13.5	2,441,849		0.0000	1.0000	94.93
14.5	2,339,557	10,650	0.0046	0.9954	94.93
15.5	2,045,367	6,357	0.0031	0.9969	94.49
16.5	1,734,538	8,194	0.0047	0.9953	94.20
17.5	1,527,704		0.0000	1.0000	93.76
18.5	1,186,361		0.0000	1.0000	93.76
19.5	1,310,263	7,301	0.0056	0.9944	93.76
20.5	1,286,758		0.0000	1.0000	93.23
21.5	1,282,662		0.0000	1.0000	93.23
22.5	1,254,702		0.0000	1.0000	93.23
23.5	1,230,185		0.0000	1.0000	93.23
24.5	1,166,393	14,994	0.0129	0.9871	93.23
25.5	1,105,620		0.0000	1.0000	92.03
26.5	1,095,835		0.0000	1.0000	92.03
27.5	857,374		0.0000	1.0000	92.03
28.5	119,715		0.0000	1.0000	92.03
29.5	18,488		0.0000	1.0000	92.03
30.5					92.03


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 352 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1973-2001 EXPERIENCE: 1929-2001 PLACEMENTS
IOWA 50-R4
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 352 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1929-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	28,467,995		0.0000	1.0000	100.00
0.5	26,254,568	7,769	0.0003	0.9997	100.00
1.5	26,580,208		0.0000	1.0000	99.97
2.5	27,111,935		0.0000	1.0000	99.97
3.5	26,836,234		0.0000	1.0000	99.97
4.5	21,065,217		0.0000	1.0000	99.97
5.5	18,901,530	9,900	0.0005	0.9995	99.97
6.5	19,010,109		0.0000	1.0000	99.92
7.5	18,654,556	79	0.0000	1.0000	99.92
8.5	18,609,600	11,050	0.0006	0.9994	99.92
9.5	18,662,676		0.0000	1.0000	99.86
10.5	18,889,682	28,471	0.0015	0.9985	99.86
11.5	18,079,319		0.0000	1.0000	99.71
12.5	16,482,606	33,007	0.0020	0.9980	99.71
13.5	15,849,837	5,018	0.0003	0.9997	99.51
14.5	14,867,600	1,202	0.0001	0.9999	99.48
15.5	8,674,095	4,597	0.0005	0.9995	99.47
16.5	8,476,737	10,850	0.0013	0.9987	99.42
17.5	6,402,557	65,749	0.0103	0.9897	99.29
18.5	6,259,790	7,248	0.0012	0.9988	98.27
19.5	6,096,030	31,645	0.0052	0.9948	98.15
20.5	5,754,624	11,600	0.0020	0.9980	97.64
21.5	4,313,728		0.0000	1.0000	97.44
22.5	3,975,224	272	0.0001	0.9999	97.44
23.5	2,965,363	1,657	0.0006	0.9994	97.43
24.5	2,791,496	194	0.0001	0.9999	97.37
25.5	2,489,649	4,406	0.0018	0.9982	97.36
26.5	1,279,092		0.0000	1.0000	97.18
27.5	1,154,977	12,265	0.0106	0.9894	97.18
28.5	1,059,817		0.0000	1.0000	96.15
29.5	1,007,355		0.0000	1.0000	96.15
30.5	964,280	66	0.0001	0.9999	96.15
31.5	939,582	117	0.0001	0.9999	96.14
32.5	1,273,264		0.0000	1.0000	96.13
33.5	959,535		0.0000	1.0000	96.13
34.5	933,724	27,657	0.0296	0.9704	96.13
35.5	904,159		0.0000	1.0000	93.28
36.5	836,302		0.0000	1.0000	93.28
37.5	833,099	2,782	0.0033	0.9967	93.28
38.5	631,667		0.0000	1.0000	92.97

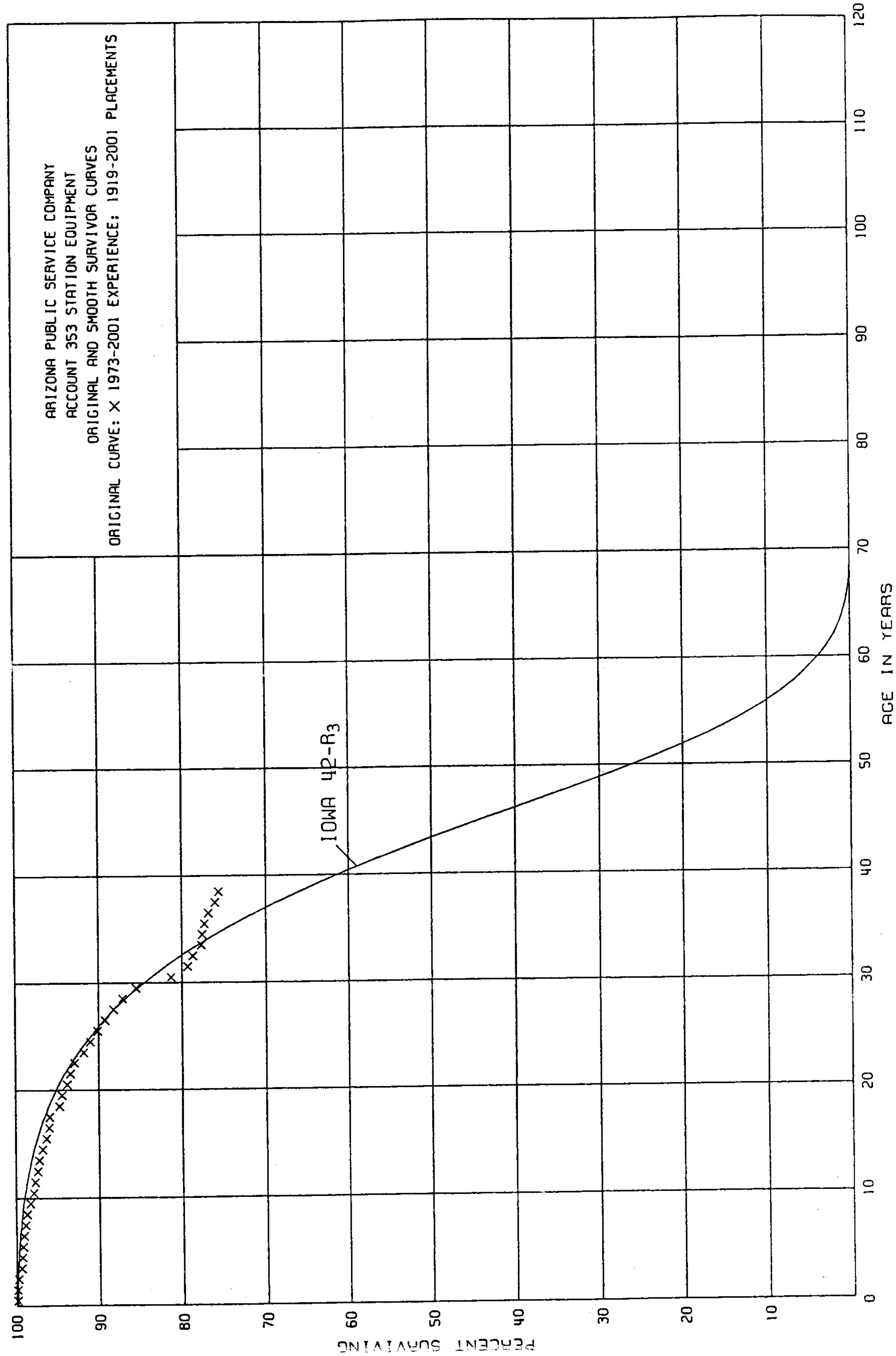
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 352 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1929-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	389,213	156	0.0004	0.9996	92.97
40.5	370,728		0.0000	1.0000	92.93
41.5	338,367		0.0000	1.0000	92.93
42.5	183,208	9,127	0.0498	0.9502	92.93
43.5	152,656		0.0000	1.0000	88.30
44.5	94,612		0.0000	1.0000	88.30
45.5	94,612		0.0000	1.0000	88.30
46.5	93,078		0.0000	1.0000	88.30
47.5	51,509		0.0000	1.0000	88.30
48.5	26,667		0.0000	1.0000	88.30
49.5	26,667		0.0000	1.0000	88.30
50.5	26,737		0.0000	1.0000	88.30
51.5	26,737		0.0000	1.0000	88.30
52.5	26,737		0.0000	1.0000	88.30
53.5	26,737		0.0000	1.0000	88.30
54.5	26,737		0.0000	1.0000	88.30
55.5	26,737		0.0000	1.0000	88.30
56.5	26,737		0.0000	1.0000	88.30
57.5	26,737		0.0000	1.0000	88.30
58.5	26,737		0.0000	1.0000	88.30
59.5	16,946		0.0000	1.0000	88.30
60.5	16,946		0.0000	1.0000	88.30
61.5	16,946		0.0000	1.0000	88.30
62.5	14,561		0.0000	1.0000	88.30
63.5	14,612		0.0000	1.0000	88.30
64.5	14,612		0.0000	1.0000	88.30
65.5	14,612		0.0000	1.0000	88.30
66.5	14,612		0.0000	1.0000	88.30
67.5	14,612		0.0000	1.0000	88.30
68.5	14,612		0.0000	1.0000	88.30
69.5	14,612		0.0000	1.0000	88.30
70.5	14,612		0.0000	1.0000	88.30
71.5	14,612		0.0000	1.0000	88.30
72.5					88.30



ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 353 STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1973-2001 EXPERIENCE; 1919-2001 PLACEMENTS
IOWA 42-R3
AGE IN YEARS
PERCENT SURVIVING
0
10
20
30
40
50
60
70
80
90
100
110
120

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1919-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	368,452,376	18,288	0.0000	1.0000	100.00
0.5	345,480,079	140,119	0.0004	0.9996	100.00
1.5	347,754,261	520,483	0.0015	0.9985	99.96
2.5	334,090,000	1,524,489	0.0046	0.9954	99.81
3.5	310,270,616	193,644	0.0006	0.9994	99.35
4.5	312,289,129	296,791	0.0010	0.9990	99.29
5.5	265,258,861	288,830	0.0011	0.9989	99.19
6.5	261,834,550	546,286	0.0021	0.9979	99.08
7.5	259,154,205	529,667	0.0020	0.9980	98.87
8.5	259,853,393	977,983	0.0038	0.9962	98.67
9.5	264,014,758	1,103,684	0.0042	0.9958	98.30
10.5	260,242,548	594,177	0.0023	0.9977	97.89
11.5	248,900,394	601,781	0.0024	0.9976	97.66
12.5	238,746,939	619,765	0.0026	0.9974	97.43
13.5	220,549,581	961,935	0.0044	0.9956	97.18
14.5	212,504,858	964,319	0.0045	0.9955	96.75
15.5	174,471,874	487,755	0.0028	0.9972	96.31
16.5	171,505,669	265,058	0.0015	0.9985	96.04
17.5	160,786,968	2,090,679	0.0130	0.9870	95.90
18.5	155,887,160	460,886	0.0030	0.9970	94.65
19.5	148,692,218	872,651	0.0059	0.9941	94.37
20.5	133,723,023	595,299	0.0045	0.9955	93.81
21.5	107,544,663	525,529	0.0049	0.9951	93.39
22.5	99,179,766	1,174,942	0.0118	0.9882	92.93
23.5	71,302,084	663,671	0.0093	0.9907	91.83
24.5	68,186,659	656,072	0.0096	0.9904	90.98
25.5	63,204,270	617,948	0.0098	0.9902	90.11
26.5	48,988,350	574,687	0.0117	0.9883	89.23
27.5	43,968,744	557,347	0.0127	0.9873	88.19
28.5	38,986,769	721,601	0.0185	0.9815	87.07
29.5	36,176,855	1,746,506	0.0483	0.9517	85.46
30.5	28,326,319	719,779	0.0254	0.9746	81.33
31.5	25,297,075	175,935	0.0070	0.9930	79.26
32.5	22,642,601	302,667	0.0134	0.9866	78.71
33.5	21,946,352	24,942	0.0011	0.9989	77.66
34.5	21,374,925	85,668	0.0040	0.9960	77.57
35.5	20,113,071	112,987	0.0056	0.9944	77.26
36.5	20,049,619	220,871	0.0110	0.9890	76.83
37.5	19,483,173	94,631	0.0049	0.9951	75.98
38.5	13,585,237	66,621	0.0049	0.9951	75.61

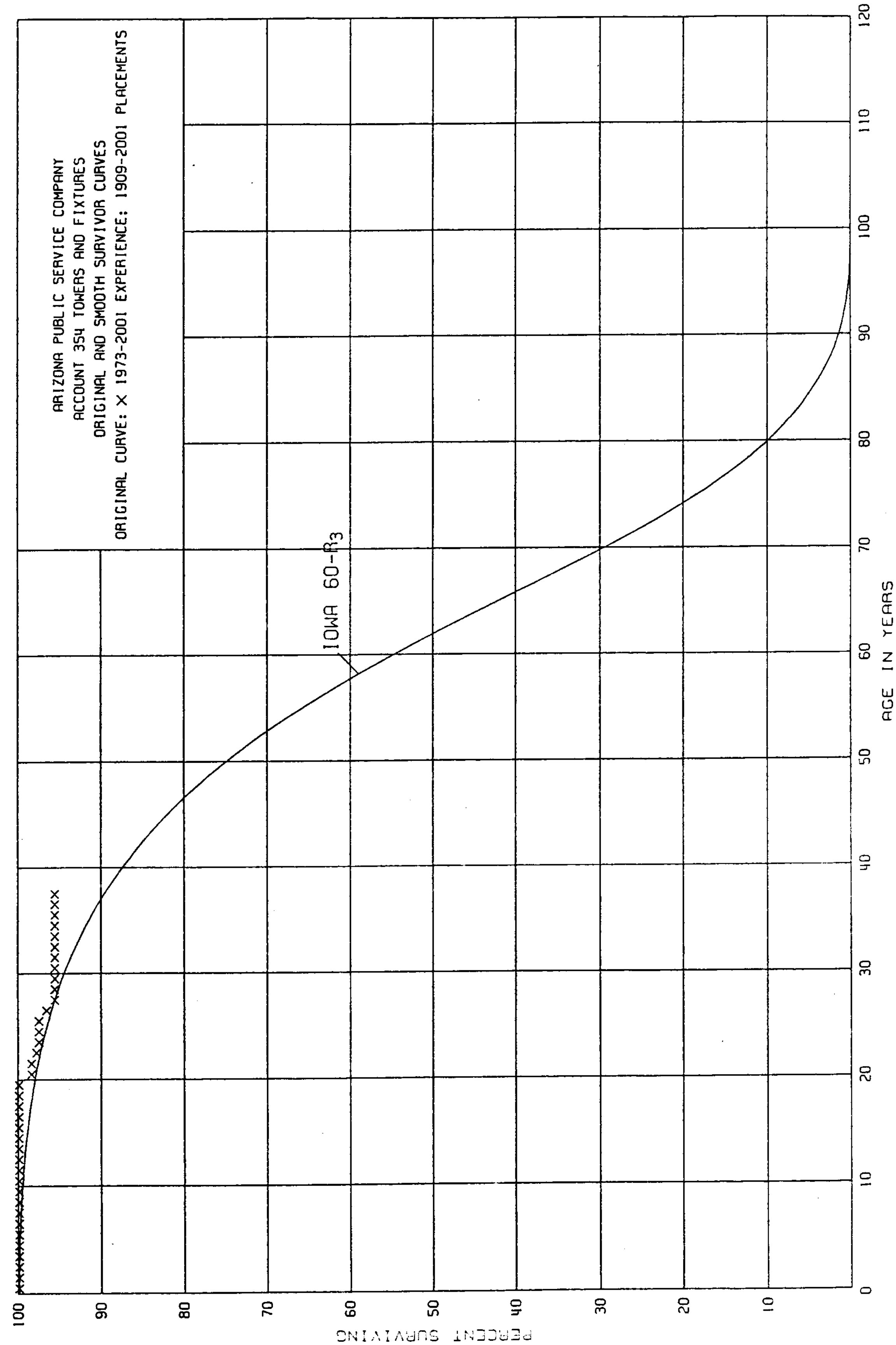
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1919-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	10,185,346	50,667	0.0050	0.9950	75.24
40.5	9,920,520	129,075	0.0130	0.9870	74.86
41.5	7,926,859	28,960	0.0037	0.9963	73.89
42.5	6,614,157	27,419	0.0041	0.9959	73.62
43.5	5,503,425	1	0.0000	1.0000	73.32
44.5	4,901,188	3,678	0.0008	0.9992	73.32
45.5	4,645,966	24,103	0.0052	0.9948	73.26
46.5	3,127,122	554	0.0002	0.9998	72.88
47.5	1,581,305	11,925	0.0075	0.9925	72.87
48.5	1,260,913	2,786	0.0022	0.9978	72.32
49.5	829,920	17,938	0.0216	0.9784	72.16
50.5	811,982	1,343	0.0017	0.9983	70.60
51.5	585,728		0.0000	1.0000	70.48
52.5	324,595	79	0.0002	0.9998	70.48
53.5	356,669	78	0.0002	0.9998	70.47
54.5	356,591	94,725	0.2656	0.7344	70.46
55.5	253,194	36,425	0.1439	0.8561	51.75
56.5	126,759	7,915	0.0624	0.9376	44.30
57.5	118,844		0.0000	1.0000	41.54
58.5	118,844		0.0000	1.0000	41.54
59.5	118,844		0.0000	1.0000	41.54
60.5	118,844		0.0000	1.0000	41.54
61.5	117,542		0.0000	1.0000	41.54
62.5	38,162		0.0000	1.0000	41.54
63.5	34,387		0.0000	1.0000	41.54
64.5	29,599	1,757	0.0594	0.9406	41.54
65.5	22,888		0.0000	1.0000	39.07
66.5	22,888		0.0000	1.0000	39.07
67.5	22,888		0.0000	1.0000	39.07
68.5	22,888		0.0000	1.0000	39.07
69.5	22,888		0.0000	1.0000	39.07
70.5	22,888		0.0000	1.0000	39.07
71.5	22,888		0.0000	1.0000	39.07
72.5					39.07


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 354 TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1973-2001 EXPERIENCE: 1909-2001 PLACEMENTS
IOWA 60-R3
PERCENT SURVIVING
AGE IN YEARS

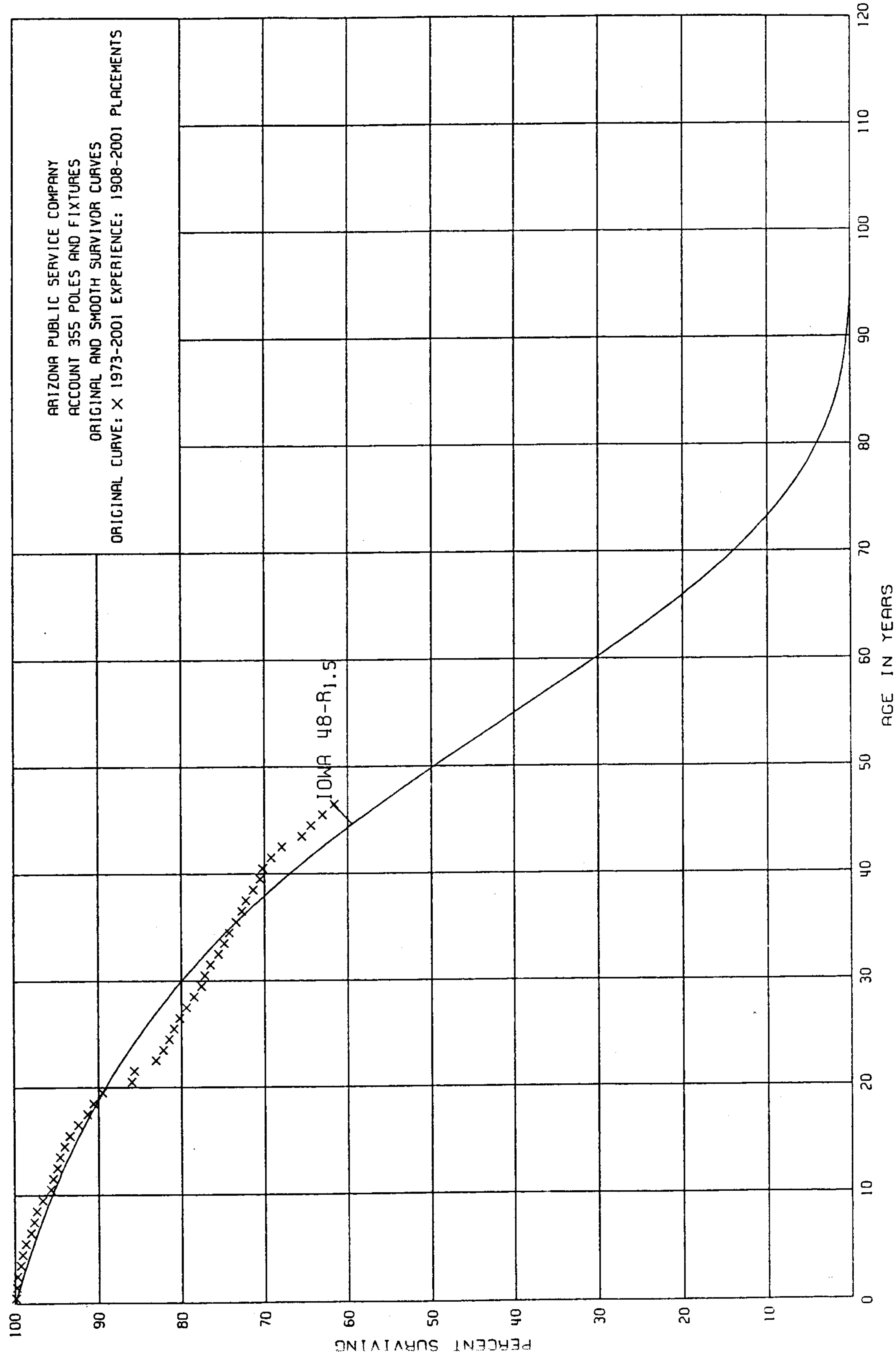
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 354 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1909-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	61,282,768		0.0000	1.0000	100.00
0.5	60,033,811		0.0000	1.0000	100.00
1.5	65,785,705		0.0000	1.0000	100.00
2.5	65,785,728		0.0000	1.0000	100.00
3.5	79,371,298		0.0000	1.0000	100.00
4.5	80,017,191		0.0000	1.0000	100.00
5.5	71,336,663		0.0000	1.0000	100.00
6.5	72,149,595		0.0000	1.0000	100.00
7.5	71,886,969		0.0000	1.0000	100.00
8.5	73,473,753		0.0000	1.0000	100.00
9.5	77,296,910		0.0000	1.0000	100.00
10.5	83,511,224	23,869	0.0003	0.9997	100.00
11.5	83,547,400		0.0000	1.0000	99.97
12.5	80,325,843		0.0000	1.0000	99.97
13.5	85,164,094		0.0000	1.0000	99.97
14.5	85,169,411		0.0000	1.0000	99.97
15.5	76,927,338		0.0000	1.0000	99.97
16.5	76,573,919	75,717	0.0010	0.9990	99.97
17.5	73,680,709		0.0000	1.0000	99.87
18.5	73,853,024		0.0000	1.0000	99.87
19.5	71,540,980	1,084,592	0.0152	0.9848	99.87
20.5	70,443,024		0.0000	1.0000	98.35
21.5	69,063,346	381,457	0.0055	0.9945	98.35
22.5	55,126,632	204,908	0.0037	0.9963	97.81
23.5	21,089,267		0.0000	1.0000	97.45
24.5	20,806,390		0.0000	1.0000	97.45
25.5	18,304,419	168,052	0.0092	0.9908	97.45
26.5	15,979,774	150,328	0.0094	0.9906	96.55
27.5	12,479,410	222	0.0000	1.0000	95.64
28.5	12,140,972		0.0000	1.0000	95.64
29.5	11,339,967		0.0000	1.0000	95.64
30.5	13,255,256	8,154	0.0006	0.9994	95.64
31.5	13,247,102		0.0000	1.0000	95.58
32.5	13,245,470	1,002	0.0001	0.9999	95.58
33.5	12,612,602	707	0.0001	0.9999	95.57
34.5	12,611,895	707	0.0001	0.9999	95.56
35.5	12,254,872		0.0000	1.0000	95.55
36.5	12,254,872		0.0000	1.0000	95.55
37.5	11,010,170		0.0000	1.0000	95.55
38.5	8,324,749		0.0000	1.0000	95.55


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 355 POLES AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1973-2001 EXPERIENCE: 1908-2001 PLACEMENTS
IOWA 48-R1.5
AGE IN YEARS
PERCENT SURVIVING

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 355 POLES AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1908-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	164,144,540	72,225	0.0004	0.9996	100.00
0.5	144,644,782	232,894	0.0016	0.9984	99.96
1.5	138,212,981	135,623	0.0010	0.9990	99.80
2.5	126,925,913	566,143	0.0045	0.9955	99.70
3.5	121,289,304	179,349	0.0015	0.9985	99.25
4.5	118,257,352	423,955	0.0036	0.9964	99.10
5.5	111,116,631	733,488	0.0066	0.9934	98.74
6.5	103,873,355	391,905	0.0038	0.9962	98.09
7.5	103,190,689	375,260	0.0036	0.9964	97.72
8.5	98,795,154	727,875	0.0074	0.9926	97.37
9.5	93,284,501	926,023	0.0099	0.9901	96.65
10.5	88,484,348	301,393	0.0034	0.9966	95.69
11.5	83,762,665	375,454	0.0045	0.9955	95.36
12.5	70,956,713	239,637	0.0034	0.9966	94.93
13.5	61,276,994	423,298	0.0069	0.9931	94.61
14.5	53,894,621	300,091	0.0056	0.9944	93.96
15.5	35,846,557	383,474	0.0107	0.9893	93.43
16.5	33,410,021	405,775	0.0121	0.9879	92.43
17.5	31,151,992	259,907	0.0083	0.9917	91.31
18.5	29,918,742	340,405	0.0114	0.9886	90.55
19.5	24,578,628	956,734	0.0389	0.9611	89.52
20.5	22,937,606	101,462	0.0044	0.9956	86.04
21.5	20,959,452	628,733	0.0300	0.9700	85.66
22.5	19,361,241	201,739	0.0104	0.9896	83.09
23.5	18,187,504	165,740	0.0091	0.9909	82.23
24.5	17,021,507	128,025	0.0075	0.9925	81.48
25.5	16,384,336	145,652	0.0089	0.9911	80.87
26.5	16,159,138	150,341	0.0093	0.9907	80.15
27.5	15,820,483	173,327	0.0110	0.9890	79.40
28.5	14,774,755	172,932	0.0117	0.9883	78.53
29.5	14,142,799	78,693	0.0056	0.9944	77.61
30.5	12,492,043	116,246	0.0093	0.9907	77.18
31.5	12,941,075	158,676	0.0123	0.9877	76.46
32.5	11,719,099	120,094	0.0102	0.9898	75.52
33.5	11,129,314	86,059	0.0077	0.9923	74.75
34.5	10,974,824	120,950	0.0110	0.9890	74.17
35.5	10,742,451	100,214	0.0093	0.9907	73.35
36.5	9,406,763	64,275	0.0068	0.9932	72.67
37.5	8,986,755	106,205	0.0118	0.9882	72.18
38.5	8,852,247	105,849	0.0120	0.9880	71.33

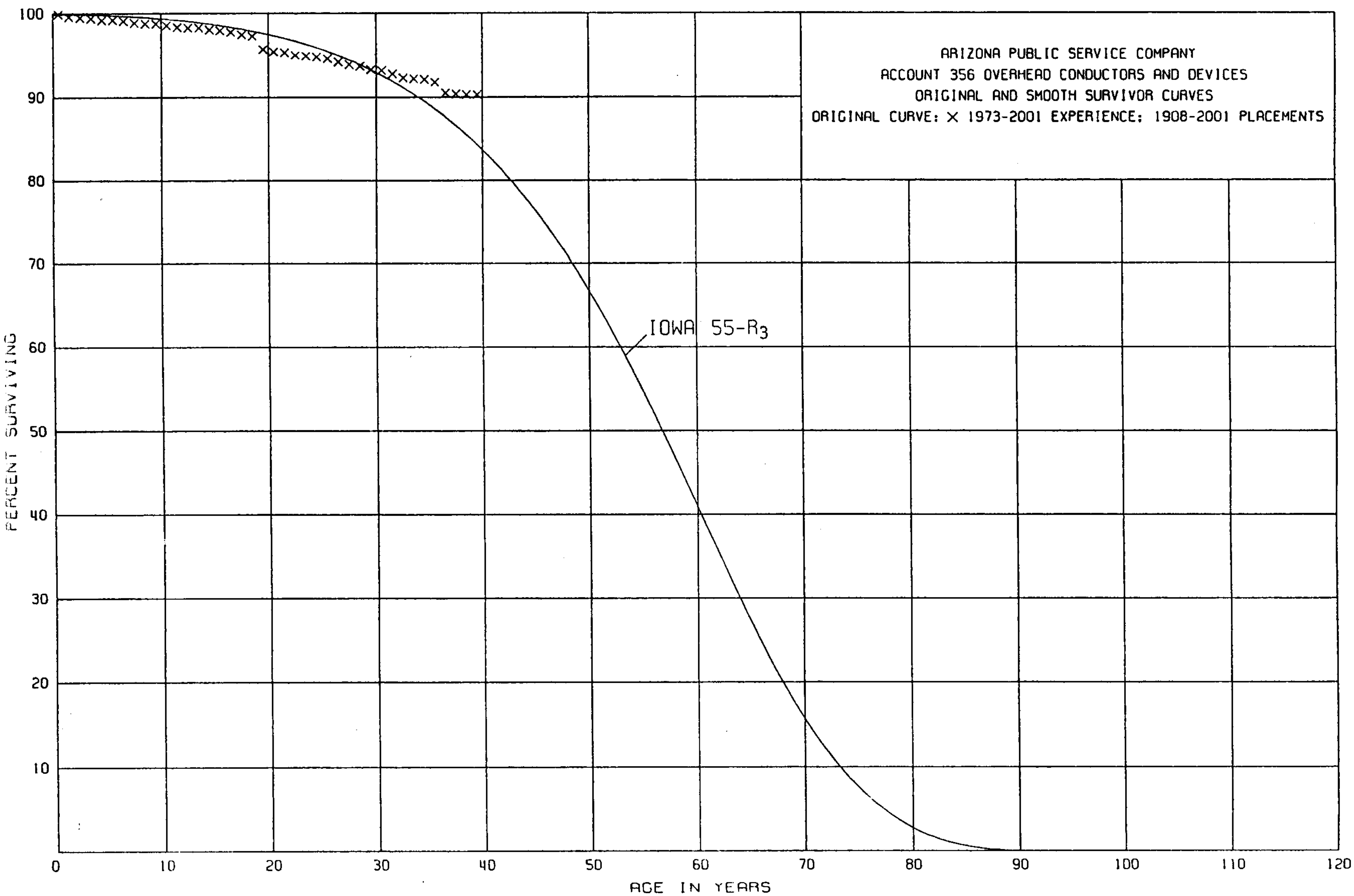
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 355 POLES AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1908-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,608,626	29,539	0.0034	0.9966	70.47
40.5	5,523,642	78,333	0.0142	0.9858	70.23
41.5	5,380,260	104,272	0.0194	0.9806	69.23
42.5	5,062,293	180,505	0.0357	0.9643	67.89
43.5	2,555,869	41,059	0.0161	0.9839	65.47
44.5	2,346,574	52,793	0.0225	0.9775	64.42
45.5	2,134,195	45,287	0.0212	0.9788	62.97
46.5	1,481,506	15,216	0.0103	0.9897	61.64
47.5	1,408,839	96,415	0.0684	0.9316	61.01
48.5	544,385	69,920	0.1284	0.8716	56.84
49.5	415,478	80,678	0.1942	0.8058	49.54
50.5	334,800	1,432	0.0043	0.9957	39.92
51.5	333,368	6,158	0.0185	0.9815	39.75
52.5	315,819	20,390	0.0646	0.9354	39.01
53.5	97,778	810	0.0083	0.9917	36.49
54.5	96,968	12,433	0.1282	0.8718	36.19
55.5	4,734	2,496	0.5272	0.4728	31.55
56.5	2,382	48	0.0202	0.9798	14.92
57.5	2,334		0.0000	1.0000	14.62
58.5	2,334		0.0000	1.0000	14.62
59.5	2,334	830	0.3556	0.6444	14.62
60.5	1,504		0.0000	1.0000	9.42
61.5	1,504	68	0.0452	0.9548	9.42
62.5	1,669		0.0000	1.0000	8.99
63.5	34,899	1,292	0.0370	0.9630	8.99
64.5	34,444		0.0000	1.0000	8.66
65.5	34,444		0.0000	1.0000	8.66
66.5	34,444	25	0.0007	0.9993	8.66
67.5	34,419	148	0.0043	0.9957	8.65
68.5	34,271		0.0000	1.0000	8.61
69.5	34,271	208	0.0061	0.9939	8.61
70.5	34,063	110	0.0032	0.9968	8.56
71.5	33,953	144	0.0042	0.9958	8.53
72.5	33,809	406	0.0120	0.9880	8.49
73.5	33,403		0.0000	1.0000	8.39
74.5	33,403	553	0.0166	0.9834	8.39
75.5	32,850	127	0.0039	0.9961	8.25
76.5	32,723	284	0.0087	0.9913	8.22
77.5	32,439		0.0000	1.0000	8.15
78.5	32,439		0.0000	1.0000	8.15



ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1973-2001 EXPERIENCE; 1908-2001 PLACEMENTS
IOWA 55-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1908-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	161,164,840	89,689	0.0006	0.9994	100.00
0.5	142,299,838	429,577	0.0030	0.9970	99.94
1.5	129,389,680	156,195	0.0012	0.9988	99.64
2.5	127,573,838	180,268	0.0014	0.9986	99.52
3.5	132,353,753	199,446	0.0015	0.9985	99.38
4.5	133,176,149	59,889	0.0004	0.9996	99.23
5.5	125,775,390	140,068	0.0011	0.9989	99.19
6.5	124,571,565	278,500	0.0022	0.9978	99.08
7.5	125,004,348	55,843	0.0004	0.9996	98.86
8.5	123,604,900	46,575	0.0004	0.9996	98.82
9.5	121,883,816	267,713	0.0022	0.9978	98.78
10.5	132,971,039	168,831	0.0013	0.9987	98.56
11.5	132,047,480	131,244	0.0010	0.9990	98.43
12.5	131,531,620	69,865	0.0005	0.9995	98.33
13.5	116,894,957	250,857	0.0021	0.9979	98.28
14.5	111,085,623	110,339	0.0010	0.9990	98.07
15.5	87,416,974	186,663	0.0021	0.9979	97.97
16.5	86,494,434	200,471	0.0023	0.9977	97.76
17.5	84,334,339	199,664	0.0024	0.9976	97.54
18.5	83,333,200	1,365,910	0.0164	0.9836	97.31
19.5	74,048,027	235,104	0.0032	0.9968	95.71
20.5	72,663,438	66,265	0.0009	0.9991	95.40
21.5	71,172,109	199,996	0.0028	0.9972	95.31
22.5	70,267,874	105,765	0.0015	0.9985	95.04
23.5	43,149,363	44,055	0.0010	0.9990	94.90
24.5	41,548,984	92,115	0.0022	0.9978	94.81
25.5	36,030,621	161,377	0.0045	0.9955	94.60
26.5	35,405,060	92,307	0.0026	0.9974	94.17
27.5	31,989,441	89,333	0.0028	0.9972	93.93
28.5	30,657,799	116,301	0.0038	0.9962	93.67
29.5	32,428,492	21,407	0.0007	0.9993	93.31
30.5	31,925,442	140,315	0.0044	0.9956	93.24
31.5	30,920,129	176,670	0.0057	0.9943	92.83
32.5	29,683,022	45,056	0.0015	0.9985	92.30
33.5	28,567,426	30,320	0.0011	0.9989	92.16
34.5	28,306,146	67,934	0.0024	0.9976	92.06
35.5	28,052,448	399,561	0.0142	0.9858	91.84
36.5	26,942,266	50,270	0.0019	0.9981	90.54
37.5	25,141,699	16,221	0.0006	0.9994	90.37
38.5	21,058,398	11,392	0.0005	0.9995	90.32

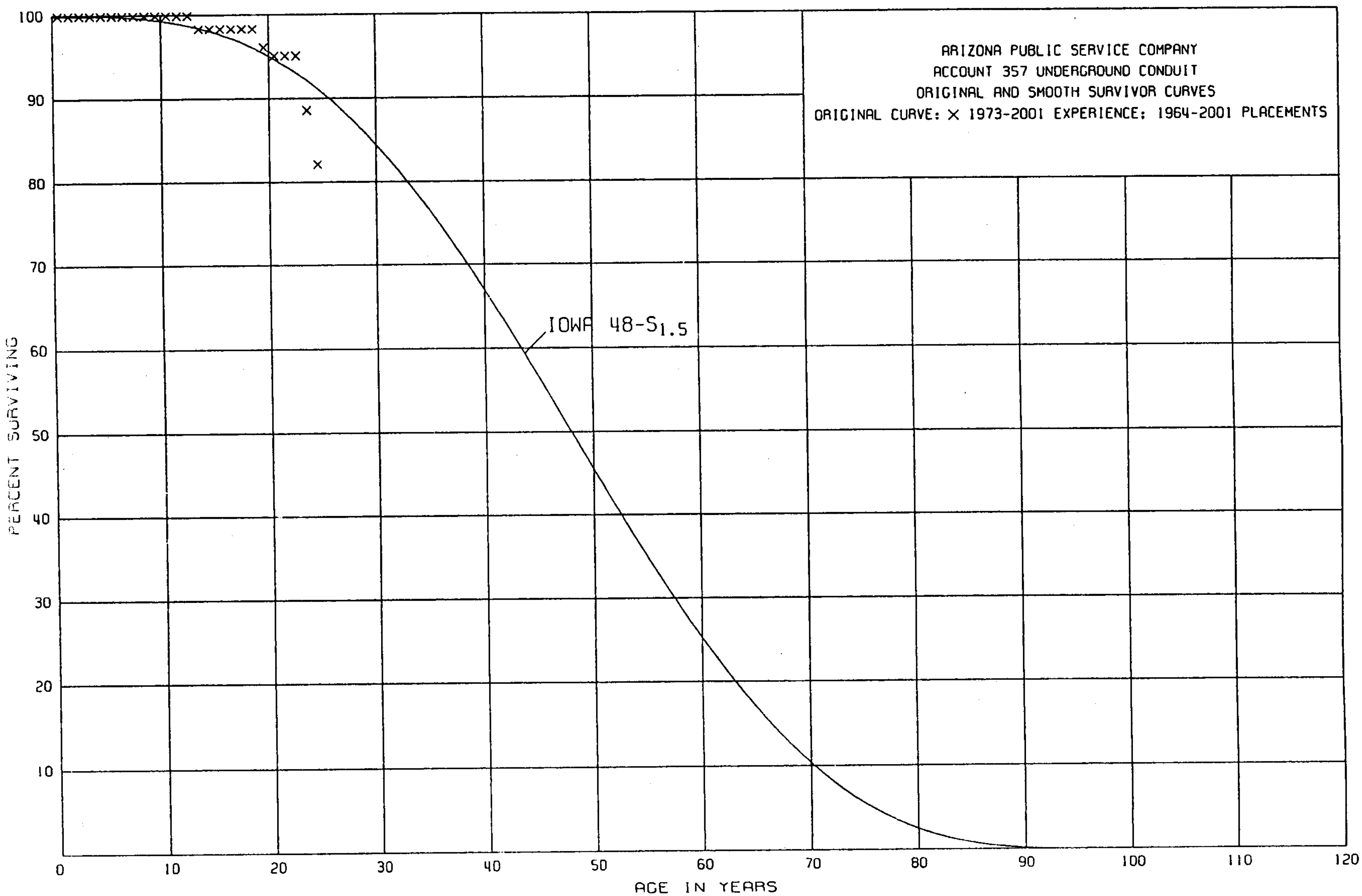
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1908-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,089,463	12,801	0.0014	0.9986	90.27
40.5	6,276,294	4,398	0.0007	0.9993	90.14
41.5	6,157,179	139,868	0.0227	0.9773	90.08
42.5	5,666,982	149,103	0.0263	0.9737	88.04
43.5	2,651,716	17,291	0.0065	0.9935	85.72
44.5	2,542,608	8,052	0.0032	0.9968	85.16
45.5	2,388,704	4,887	0.0020	0.9980	84.89
46.5	1,525,133	2,150	0.0014	0.9986	84.72
47.5	1,462,583	20,662	0.0141	0.9859	84.60
48.5	645,852	9,319	0.0144	0.9856	83.41
49.5	507,132	64,610	0.1274	0.8726	82.21
50.5	401,561		0.0000	1.0000	71.74
51.5	401,561	120	0.0003	0.9997	71.74
52.5	381,483	1,091	0.0029	0.9971	71.72
53.5	125,388		0.0000	1.0000	71.51
54.5	125,388		0.0000	1.0000	71.51
55.5	544		0.0000	1.0000	71.51
56.5	1,088		0.0000	1.0000	71.51
57.5	1,088		0.0000	1.0000	71.51
58.5	1,088		0.0000	1.0000	71.51
59.5	1,088		0.0000	1.0000	71.51
60.5	1,088		0.0000	1.0000	71.51
61.5	1,088		0.0000	1.0000	71.51
62.5	1,088		0.0000	1.0000	71.51
63.5	73,102		0.0000	1.0000	71.51
64.5	75,398	544	0.0072	0.9928	71.51
65.5	74,854		0.0000	1.0000	71.00
66.5	74,854		0.0000	1.0000	71.00
67.5	74,854	136	0.0018	0.9982	71.00
68.5	74,718		0.0000	1.0000	70.87
69.5	74,718		0.0000	1.0000	70.87
70.5	74,718	8	0.0001	0.9999	70.87
71.5	74,710	544	0.0073	0.9927	70.86
72.5	74,166		0.0000	1.0000	70.34
73.5	74,166		0.0000	1.0000	70.34
74.5	74,166	2,296	0.0310	0.9690	70.34
75.5	71,870		0.0000	1.0000	68.16
76.5	71,870		0.0000	1.0000	68.16
77.5	71,870		0.0000	1.0000	68.16
78.5	71,870		0.0000	1.0000	68.16


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 357 UNDERGROUND CONDUIT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1973-2001 EXPERIENCE; 1964-2001 PLACEMENTS
IOWA 48-S1.5
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

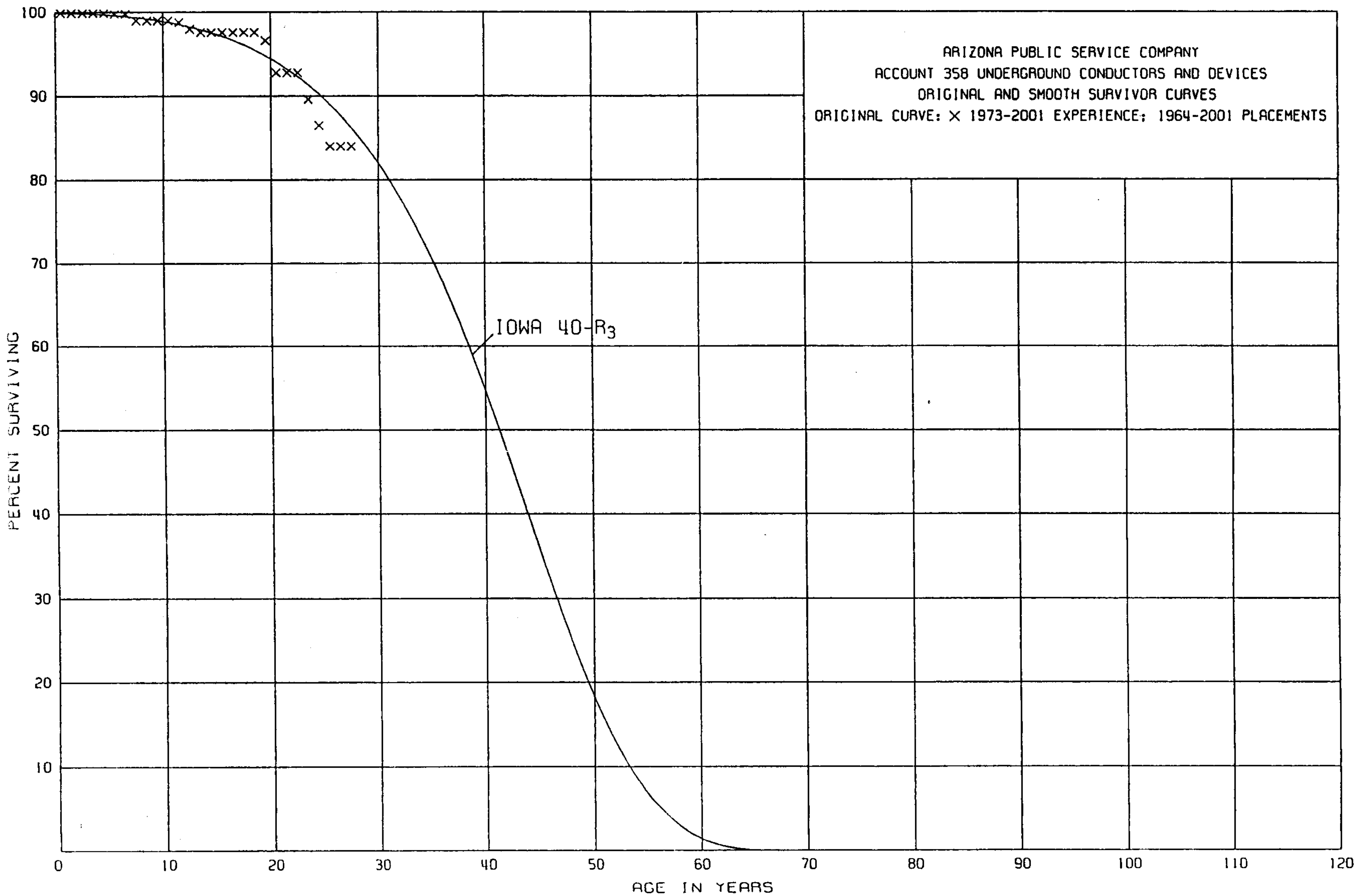
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 357 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1964-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,570,238	76	0.0000	1.0000	100.00
0.5	9,301,167		0.0000	1.0000	100.00
1.5	8,726,288		0.0000	1.0000	100.00
2.5	7,499,684	175	0.0000	1.0000	100.00
3.5	7,484,143		0.0000	1.0000	100.00
4.5	6,643,742	1,664	0.0003	0.9997	100.00
5.5	6,642,811		0.0000	1.0000	99.97
6.5	5,416,795	5,252	0.0010	0.9990	99.97
7.5	5,411,543		0.0000	1.0000	99.87
8.5	5,507,646		0.0000	1.0000	99.87
9.5	5,507,646		0.0000	1.0000	99.87
10.5	5,507,646		0.0000	1.0000	99.87
11.5	5,124,447		0.0000	1.0000	99.87
12.5	5,124,131	82,131	0.0160	0.9840	99.87
13.5	5,008,690		0.0000	1.0000	98.27
14.5	4,959,741		0.0000	1.0000	98.27
15.5	4,958,643		0.0000	1.0000	98.27
16.5	4,448,280		0.0000	1.0000	98.27
17.5	3,334,966		0.0000	1.0000	98.27
18.5	5,212,745	116,469	0.0223	0.9777	98.27
19.5	4,332,871	43,825	0.0101	0.9899	96.08
20.5	4,289,046		0.0000	1.0000	95.11
21.5	4,283,156		0.0000	1.0000	95.11
22.5	4,252,078	290,970	0.0684	0.9316	95.11
23.5	3,961,108	290,994	0.0735	0.9265	88.60
24.5	3,670,114		0.0000	1.0000	82.09
25.5	3,670,114		0.0000	1.0000	82.09
26.5	3,670,114		0.0000	1.0000	82.09
27.5	313,198		0.0000	1.0000	82.09
28.5	313,198		0.0000	1.0000	82.09
29.5	313,198		0.0000	1.0000	82.09
30.5	298,173		0.0000	1.0000	82.09
31.5	298,173		0.0000	1.0000	82.09
32.5	298,173		0.0000	1.0000	82.09
33.5	298,173		0.0000	1.0000	82.09
34.5	298,173		0.0000	1.0000	82.09
35.5	96,103		0.0000	1.0000	82.09
36.5	96,103		0.0000	1.0000	82.09
37.5					82.09


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 358 UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1973-2001 EXPERIENCE; 1964-2001 PLACEMENTS
IOWA 40-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

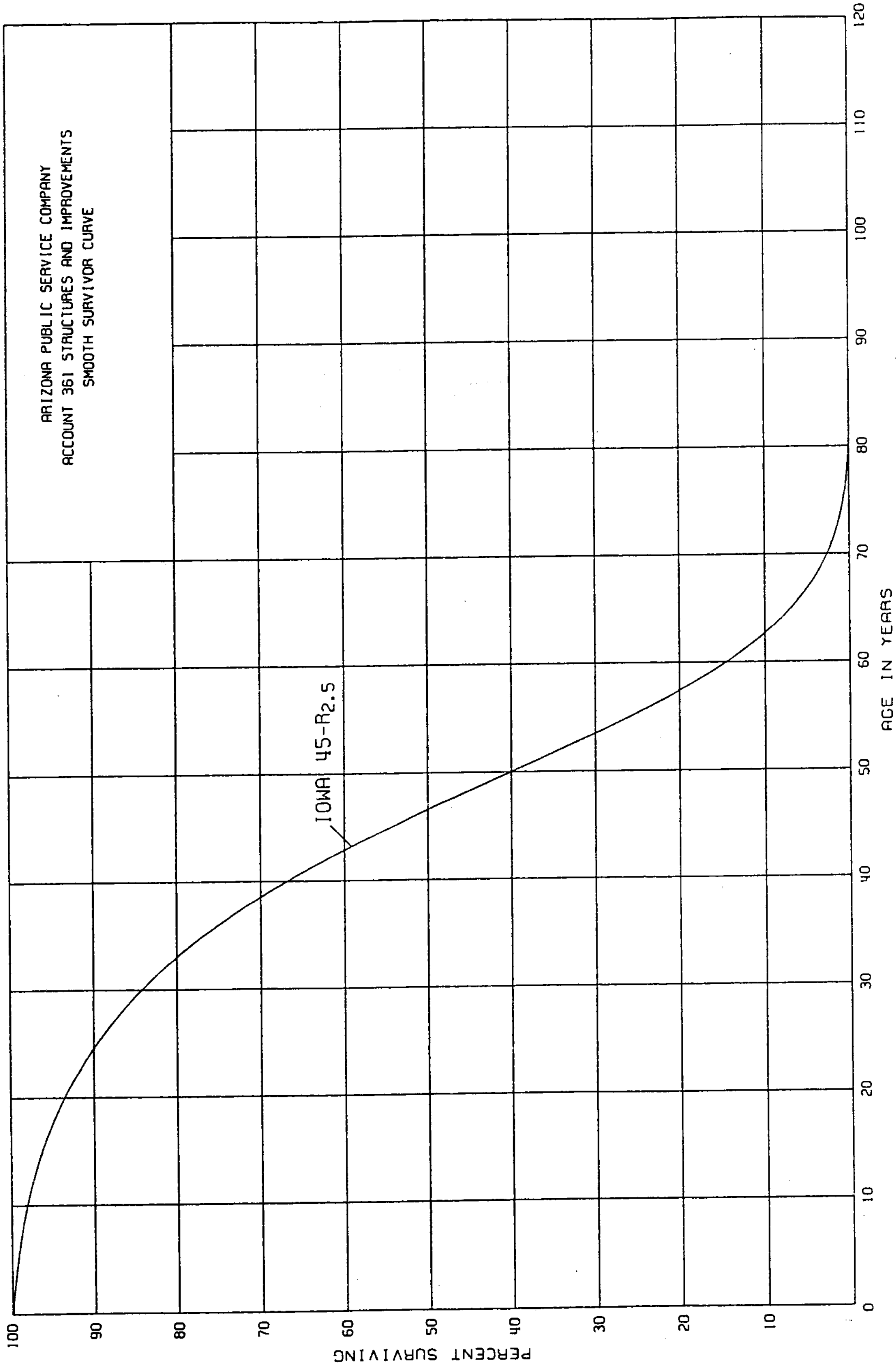
ARIZONA PUBLIC SERVICE COMPANY

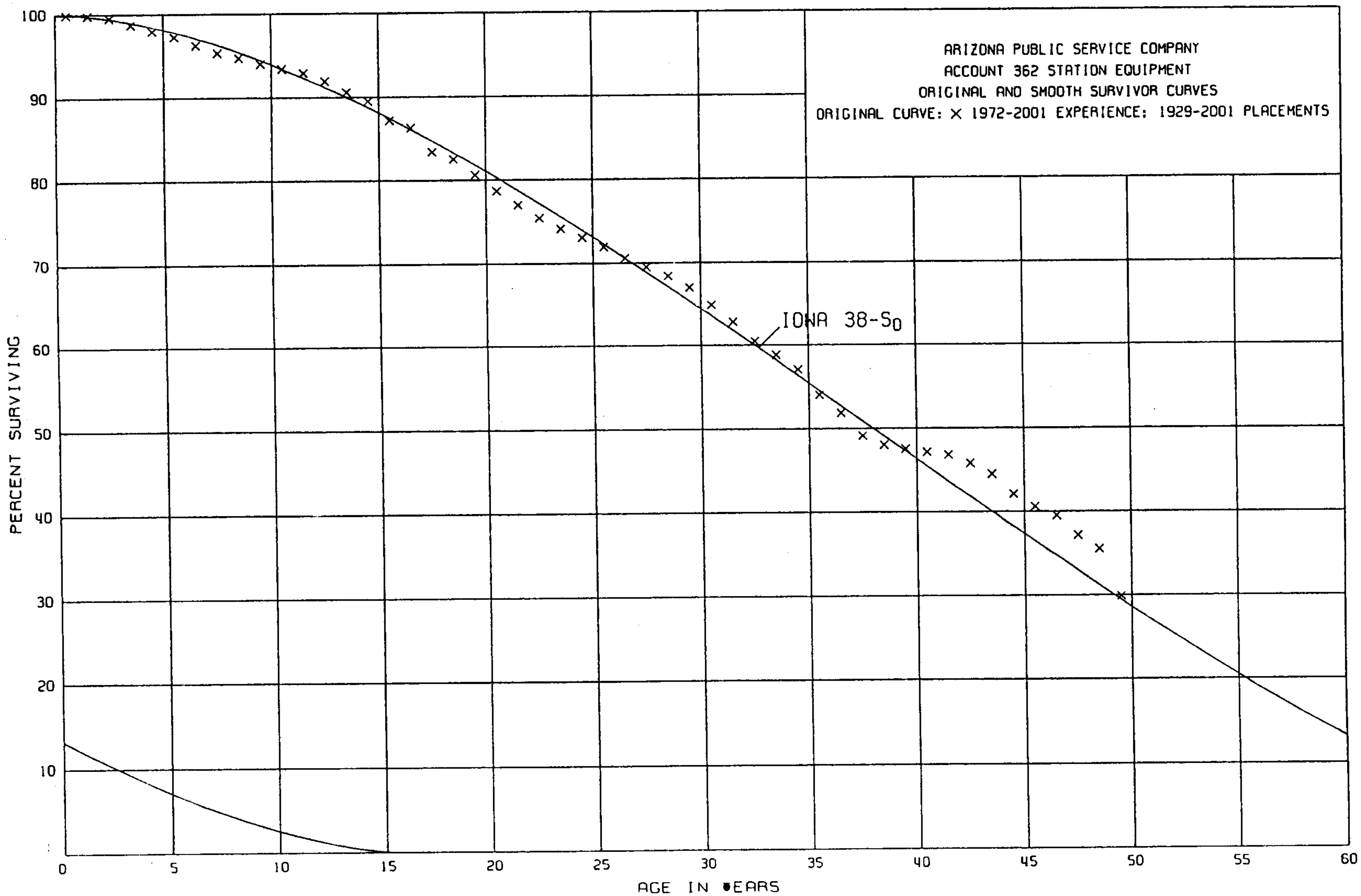
ACCOUNT 358 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1964-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	17,564,056	2,863	0.0002	0.9998	100.00
0.5	16,419,644	120	0.0000	1.0000	99.98
1.5	14,117,523		0.0000	1.0000	99.98
2.5	12,798,335		0.0000	1.0000	99.98
3.5	12,814,583		0.0000	1.0000	99.98
4.5	12,643,234	26,808	0.0021	0.9979	99.98
5.5	12,617,169		0.0000	1.0000	99.77
6.5	12,509,514	98,394	0.0079	0.9921	99.77
7.5	12,259,090		0.0000	1.0000	98.98
8.5	12,276,989	3,605	0.0003	0.9997	98.98
9.5	12,221,515		0.0000	1.0000	98.95
10.5	12,221,515	22,233	0.0018	0.9982	98.95
11.5	10,904,993	87,593	0.0080	0.9920	98.77
12.5	9,558,793	38,211	0.0040	0.9960	97.98
13.5	9,424,249		0.0000	1.0000	97.59
14.5	9,289,125		0.0000	1.0000	97.59
15.5	9,280,674		0.0000	1.0000	97.59
16.5	6,424,526		0.0000	1.0000	97.59
17.5	6,316,056		0.0000	1.0000	97.59
18.5	8,052,124	78,472	0.0097	0.9903	97.59
19.5	7,973,652	318,029	0.0399	0.9601	96.64
20.5	7,655,623		0.0000	1.0000	92.78
21.5	7,634,365		0.0000	1.0000	92.78
22.5	6,845,006	232,409	0.0340	0.9660	92.78
23.5	6,612,597	232,481	0.0352	0.9648	89.63
24.5	6,196,570	181,684	0.0293	0.9707	86.48
25.5	6,014,886		0.0000	1.0000	83.95
26.5	6,014,886		0.0000	1.0000	83.95
27.5	549,113		0.0000	1.0000	83.95
28.5	407,226		0.0000	1.0000	83.95
29.5	407,226		0.0000	1.0000	83.95
30.5	407,226		0.0000	1.0000	83.95
31.5	407,226		0.0000	1.0000	83.95
32.5	407,226		0.0000	1.0000	83.95
33.5	381,974		0.0000	1.0000	83.95
34.5	381,974		0.0000	1.0000	83.95
35.5	25,243		0.0000	1.0000	83.95
36.5	25,243		0.0000	1.0000	83.95
37.5					83.95


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 361 STRUCTURES AND IMPROVEMENTS
SMOOTH SURVIVOR CURVE
IOWA 45-R2.5
AGE IN YEARS
PERCENT SURVIVING
0
10
20
30
40
50
60
70
80
90
100
110
120


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 362 STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1972-2001 EXPERIENCE: 1929-2001 PLACEMENTS
IOWA 38-S0
PERCENT SURVIVING
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30
35
40
45
50
55
60
AGE IN YEARS

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 362 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1929-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	199,344,754	177,990	0.0009	0.9991	100.00
0.5	178,081,270	147,196	0.0008	0.9992	99.91
1.5	165,522,817	502,378	0.0030	0.9970	99.83
2.5	147,870,341	1,203,609	0.0081	0.9919	99.53
3.5	136,257,373	1,189,561	0.0087	0.9913	98.72
4.5	126,617,470	909,192	0.0072	0.9928	97.86
5.5	118,474,901	1,120,093	0.0095	0.9905	97.16
6.5	113,120,004	1,072,910	0.0095	0.9905	96.24
7.5	109,496,590	680,161	0.0062	0.9938	95.33
8.5	104,877,529	783,480	0.0075	0.9925	94.74
9.5	102,526,677	710,965	0.0069	0.9931	94.03
10.5	97,981,491	482,632	0.0049	0.9951	93.38
11.5	93,461,221	1,057,650	0.0113	0.9887	92.92
12.5	88,500,208	1,276,246	0.0144	0.9856	91.87
13.5	77,721,411	945,262	0.0122	0.9878	90.55
14.5	72,093,865	1,783,206	0.0247	0.9753	89.45
15.5	63,337,919	714,976	0.0113	0.9887	87.24
16.5	56,469,117	1,898,274	0.0336	0.9664	86.25
17.5	50,414,742	544,031	0.0108	0.9892	83.35
18.5	45,990,965	1,032,964	0.0225	0.9775	82.45
19.5	41,308,470	993,697	0.0241	0.9759	80.59
20.5	37,926,914	785,951	0.0207	0.9793	78.65
21.5	34,583,366	723,661	0.0209	0.9791	77.02
22.5	28,818,961	494,980	0.0172	0.9828	75.41
23.5	25,426,849	400,439	0.0157	0.9843	74.11
24.5	23,220,345	351,690	0.0151	0.9849	72.95
25.5	21,960,536	369,372	0.0168	0.9832	71.85
26.5	20,744,469	329,382	0.0159	0.9841	70.64
27.5	17,934,541	277,262	0.0155	0.9845	69.52
28.5	16,149,741	352,576	0.0218	0.9782	68.44
29.5	13,350,848	411,573	0.0308	0.9692	66.95
30.5	12,270,631	390,234	0.0318	0.9682	64.89
31.5	10,281,012	375,033	0.0365	0.9635	62.83
32.5	9,104,977	260,616	0.0286	0.9714	60.54
33.5	8,206,028	238,495	0.0291	0.9709	58.81
34.5	7,220,118	374,505	0.0519	0.9481	57.10
35.5	6,089,072	253,729	0.0417	0.9583	54.14
36.5	5,589,143	304,304	0.0544	0.9456	51.88
37.5	5,140,971	111,666	0.0217	0.9783	49.06
38.5	4,616,831	43,830	0.0095	0.9905	48.00

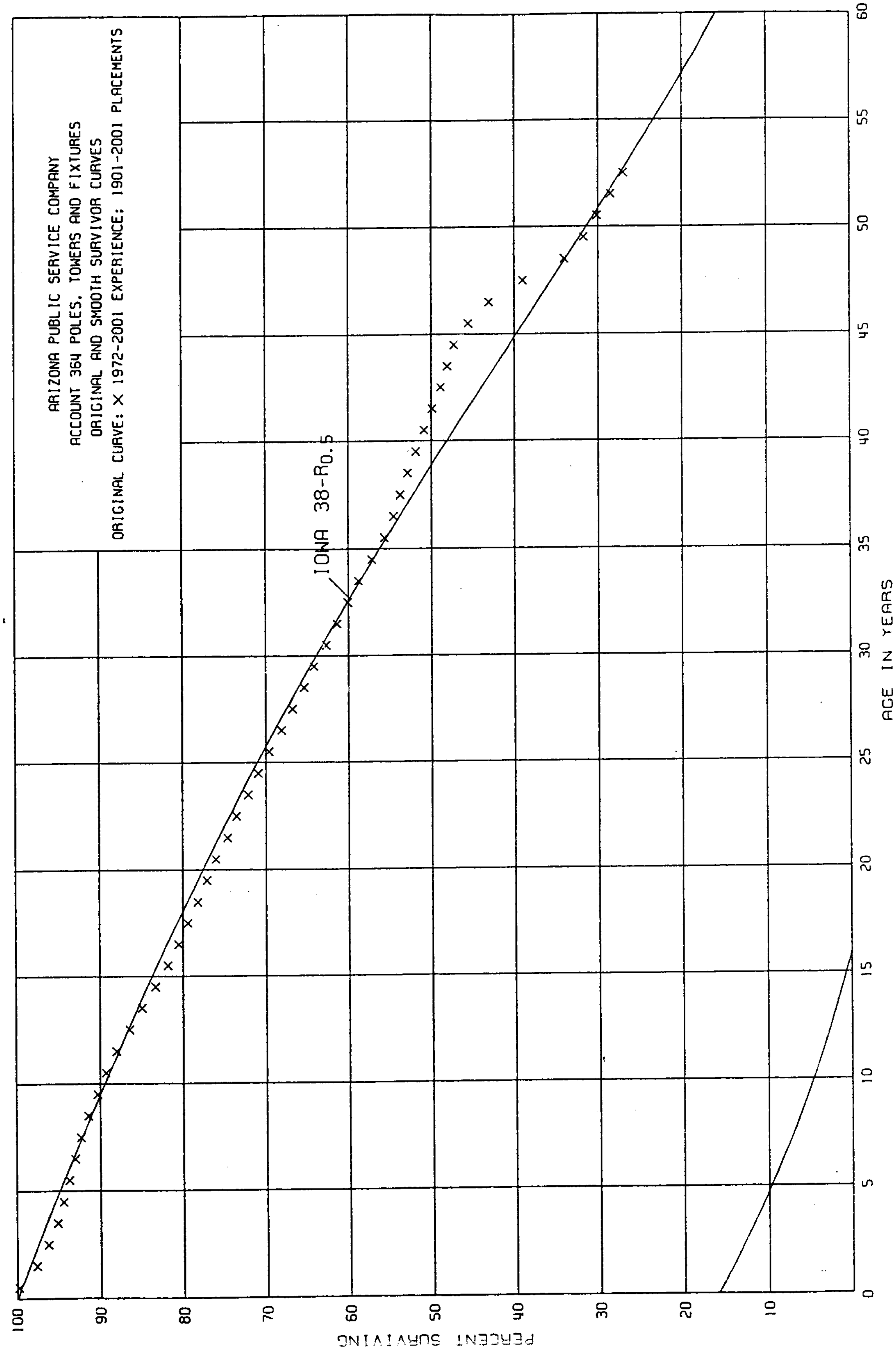
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 362 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1929-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,623,494	34,553	0.0095	0.9905	47.54
40.5	3,438,808	23,154	0.0067	0.9933	47.09
41.5	2,927,615	60,577	0.0207	0.9793	46.77
42.5	2,776,800	78,039	0.0281	0.9719	45.80
43.5	2,648,433	145,774	0.0550	0.9450	44.51
44.5	2,552,939	89,692	0.0351	0.9649	42.06
45.5	2,153,935	55,206	0.0256	0.9744	40.58
46.5	1,677,272	105,175	0.0627	0.9373	39.54
47.5	1,385,357	58,391	0.0421	0.9579	37.06
48.5	1,190,912	188,891	0.1586	0.8414	35.50
49.5	781,162	1,371	0.0018	0.9982	29.87
50.5	868,851	5,536	0.0064	0.9936	29.82
51.5	730,477		0.0000	1.0000	29.63
52.5	543,214		0.0000	1.0000	29.63
53.5	295,436		0.0000	1.0000	29.63
54.5	260,210		0.0000	1.0000	29.63
55.5	251,918	4,564	0.0181	0.9819	29.63
56.5	166,809		0.0000	1.0000	29.09
57.5	202,521	641	0.0032	0.9968	29.09
58.5	198,483	38,533	0.1941	0.8059	29.00
59.5	55,547		0.0000	1.0000	23.37
60.5	50,178		0.0000	1.0000	23.37
61.5	49,125		0.0000	1.0000	23.37
62.5	36,982		0.0000	1.0000	23.37
63.5	46,362		0.0000	1.0000	23.37
64.5	46,362		0.0000	1.0000	23.37
65.5	46,362		0.0000	1.0000	23.37
66.5	10,650		0.0000	1.0000	23.37
67.5	10,650		0.0000	1.0000	23.37
68.5	10,650		0.0000	1.0000	23.37
69.5	10,650		0.0000	1.0000	23.37
70.5	10,650		0.0000	1.0000	23.37
71.5	10,650		0.0000	1.0000	23.37
72.5					23.37


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 364 POLES, TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1972-2001 EXPERIENCE; 1901-2001 PLACEMENTS
IOWA 38-R0.5
AGE IN YEARS
PERCENT SURVIVING

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 364 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1901-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	364,125,423	868,548	0.0024	0.9976	100.00
0.5	354,320,317	7,532,719	0.0213	0.9787	99.76
1.5	331,635,833	4,792,513	0.0145	0.9855	97.64
2.5	318,112,974	3,644,868	0.0115	0.9885	96.22
3.5	308,430,157	2,182,521	0.0071	0.9929	95.11
4.5	287,765,699	2,238,658	0.0078	0.9922	94.43
5.5	265,728,507	1,924,817	0.0072	0.9928	93.69
6.5	244,094,523	1,971,194	0.0081	0.9919	93.02
7.5	217,328,454	2,160,080	0.0099	0.9901	92.27
8.5	204,761,895	2,305,600	0.0113	0.9887	91.36
9.5	190,309,850	2,197,128	0.0115	0.9885	90.33
10.5	175,421,163	2,487,736	0.0142	0.9858	89.29
11.5	155,116,545	2,835,766	0.0183	0.9817	88.02
12.5	132,864,619	2,259,094	0.0170	0.9830	86.41
13.5	124,311,630	2,365,404	0.0190	0.9810	84.94
14.5	105,579,143	1,930,319	0.0183	0.9817	83.33
15.5	95,691,875	1,494,913	0.0156	0.9844	81.81
16.5	83,072,697	1,138,930	0.0137	0.9863	80.53
17.5	77,707,439	1,175,029	0.0151	0.9849	79.43
18.5	71,140,532	1,027,073	0.0144	0.9856	78.23
19.5	65,648,589	961,051	0.0146	0.9854	77.10
20.5	56,792,025	994,337	0.0175	0.9825	75.97
21.5	51,641,186	816,344	0.0158	0.9842	74.64
22.5	47,273,416	880,197	0.0186	0.9814	73.46
23.5	42,370,073	728,903	0.0172	0.9828	72.09
24.5	38,380,374	692,322	0.0180	0.9820	70.85
25.5	32,947,211	711,575	0.0216	0.9784	69.57
26.5	28,675,730	557,339	0.0194	0.9806	68.07
27.5	25,503,756	502,956	0.0197	0.9803	66.75
28.5	23,106,804	439,189	0.0190	0.9810	65.44
29.5	20,715,163	473,405	0.0229	0.9771	64.20
30.5	18,264,977	391,930	0.0215	0.9785	62.73
31.5	19,353,734	399,757	0.0207	0.9793	61.38
32.5	17,483,643	388,068	0.0222	0.9778	60.11
33.5	15,537,448	415,486	0.0267	0.9733	58.78
34.5	13,737,843	371,910	0.0271	0.9729	57.21
35.5	14,140,943	262,654	0.0186	0.9814	55.66
36.5	12,909,789	185,005	0.0143	0.9857	54.62
37.5	12,699,508	232,871	0.0183	0.9817	53.84
38.5	11,236,893	211,544	0.0188	0.9812	52.85

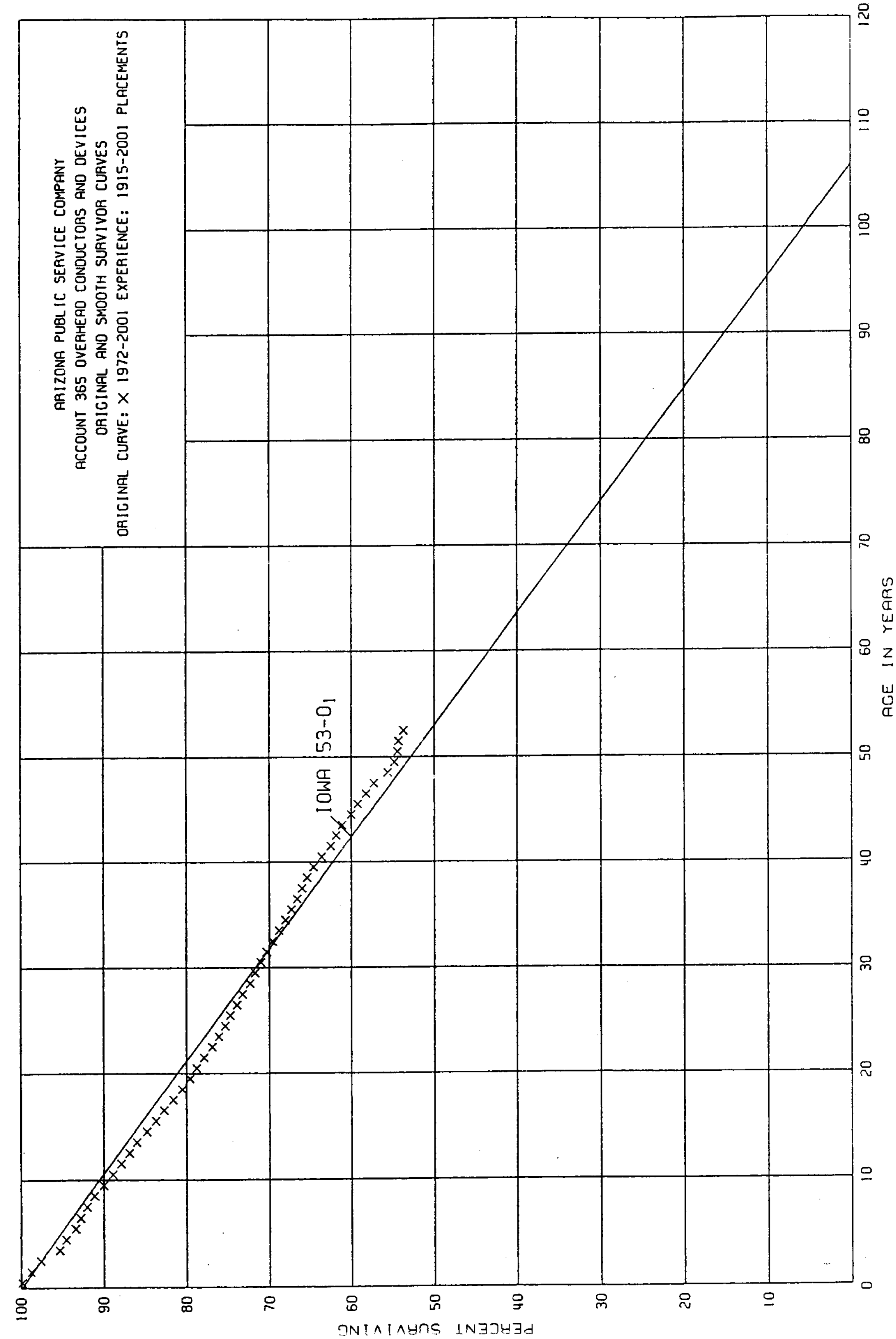
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 364 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	10,006,944	187,135	0.0187	0.9813	51.86
40.5	8,897,358	173,375	0.0195	0.9805	50.89
41.5	6,978,659	133,719	0.0192	0.9808	49.90
42.5	6,870,883	121,714	0.0177	0.9823	48.94
43.5	6,227,381	106,232	0.0171	0.9829	48.07
44.5	3,807,946	136,710	0.0359	0.9641	47.25
45.5	3,067,472	168,445	0.0549	0.9451	45.55
46.5	1,794,331	168,343	0.0938	0.9062	43.05
47.5	1,628,190	208,433	0.1280	0.8720	39.01
48.5	1,420,136	97,978	0.0690	0.9310	34.02
49.5	1,322,237	64,583	0.0488	0.9512	31.67
50.5	1,259,295	67,706	0.0538	0.9462	30.12
51.5	1,191,961	63,421	0.0532	0.9468	28.50
52.5	1,891	629	0.3326	0.6674	26.98
53.5	1,644	1,115	0.6782	0.3218	18.01
54.5	1,286	1,110	0.8631	0.1369	5.80
55.5	1,057	552	0.5222	0.4778	0.79
56.5	1,013	746	0.7364	0.2636	0.38
57.5	569	355	0.6239	0.3761	0.10
58.5	214	110	0.5140	0.4860	0.04
59.5	147	104	0.7075	0.2925	0.02
60.5	1,109	104	0.0938	0.9062	0.01
61.5	2,887	2,752	0.9532	0.0468	0.01
62.5	289	136	0.4706	0.5294	0.00
63.5	153	18	0.1176	0.8824	0.00
64.5	568	135	0.2377	0.7623	0.00
65.5	1,598	1,113	0.6965	0.3035	0.00
66.5	485		0.0000	1.0000	0.00
67.5	537	433	0.8063	0.1937	0.00
68.5	104	104	1.0000	0.0000	0.00
69.5	240	240	1.0000	0.0000	0.00
70.5					0.00
71.5					
72.5	80		0.0000		
73.5	80		0.0000		
74.5	80	36	0.4500		
75.5	44	44	1.0000		
76.5					
77.5	210		0.0000		
78.5	210		0.0000		


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1972-2001 EXPERIENCE; 1915-2001 PLACEMENTS
IOWA 53-O1
AGE IN YEARS
PERCENT SURVIVING
0
10
20
30
40
50
60
70
80
90
100
110
120

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1915-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	208,808,502	245,878	0.0012	0.9988	100.00
0.5	202,278,009	2,216,859	0.0110	0.9890	99.88
1.5	199,338,305	2,495,343	0.0125	0.9875	98.78
2.5	193,245,840	4,509,866	0.0233	0.9767	97.55
3.5	194,844,438	1,634,144	0.0084	0.9916	95.28
4.5	196,368,639	2,259,977	0.0115	0.9885	94.48
5.5	182,101,407	1,260,722	0.0069	0.9931	93.39
6.5	172,326,524	1,346,695	0.0078	0.9922	92.75
7.5	157,491,449	1,628,065	0.0103	0.9897	92.03
8.5	142,238,040	1,704,382	0.0120	0.9880	91.08
9.5	138,694,340	1,765,170	0.0127	0.9873	89.99
10.5	126,562,462	1,342,228	0.0106	0.9894	88.85
11.5	116,901,021	1,366,198	0.0117	0.9883	87.91
12.5	97,113,377	937,772	0.0097	0.9903	86.88
13.5	82,219,573	1,177,080	0.0143	0.9857	86.04
14.5	80,981,435	1,089,844	0.0135	0.9865	84.81
15.5	75,395,687	882,598	0.0117	0.9883	83.67
16.5	75,732,097	1,018,596	0.0134	0.9866	82.69
17.5	72,044,113	986,579	0.0137	0.9863	81.58
18.5	65,836,393	711,622	0.0108	0.9892	80.46
19.5	61,692,548	606,302	0.0098	0.9902	79.59
20.5	54,564,000	666,636	0.0122	0.9878	78.81
21.5	50,534,817	623,594	0.0123	0.9877	77.85
22.5	46,392,853	498,971	0.0108	0.9892	76.89
23.5	42,351,835	411,299	0.0097	0.9903	76.06
24.5	38,699,697	321,426	0.0083	0.9917	75.32
25.5	34,647,023	380,753	0.0110	0.9890	74.69
26.5	31,133,305	304,002	0.0098	0.9902	73.87
27.5	28,615,761	318,411	0.0111	0.9889	73.15
28.5	25,943,546	222,141	0.0086	0.9914	72.34
29.5	23,203,880	226,324	0.0098	0.9902	71.72
30.5	20,515,185	203,503	0.0099	0.9901	71.02
31.5	21,795,706	214,115	0.0098	0.9902	70.32
32.5	19,459,352	238,393	0.0123	0.9877	69.63
33.5	17,124,239	195,682	0.0114	0.9886	68.77
34.5	14,778,922	156,526	0.0106	0.9894	67.99
35.5	13,836,947	130,175	0.0094	0.9906	67.27
36.5	12,280,193	112,670	0.0092	0.9908	66.64
37.5	11,267,469	103,962	0.0092	0.9908	66.03
38.5	9,660,661	125,754	0.0130	0.9870	65.42

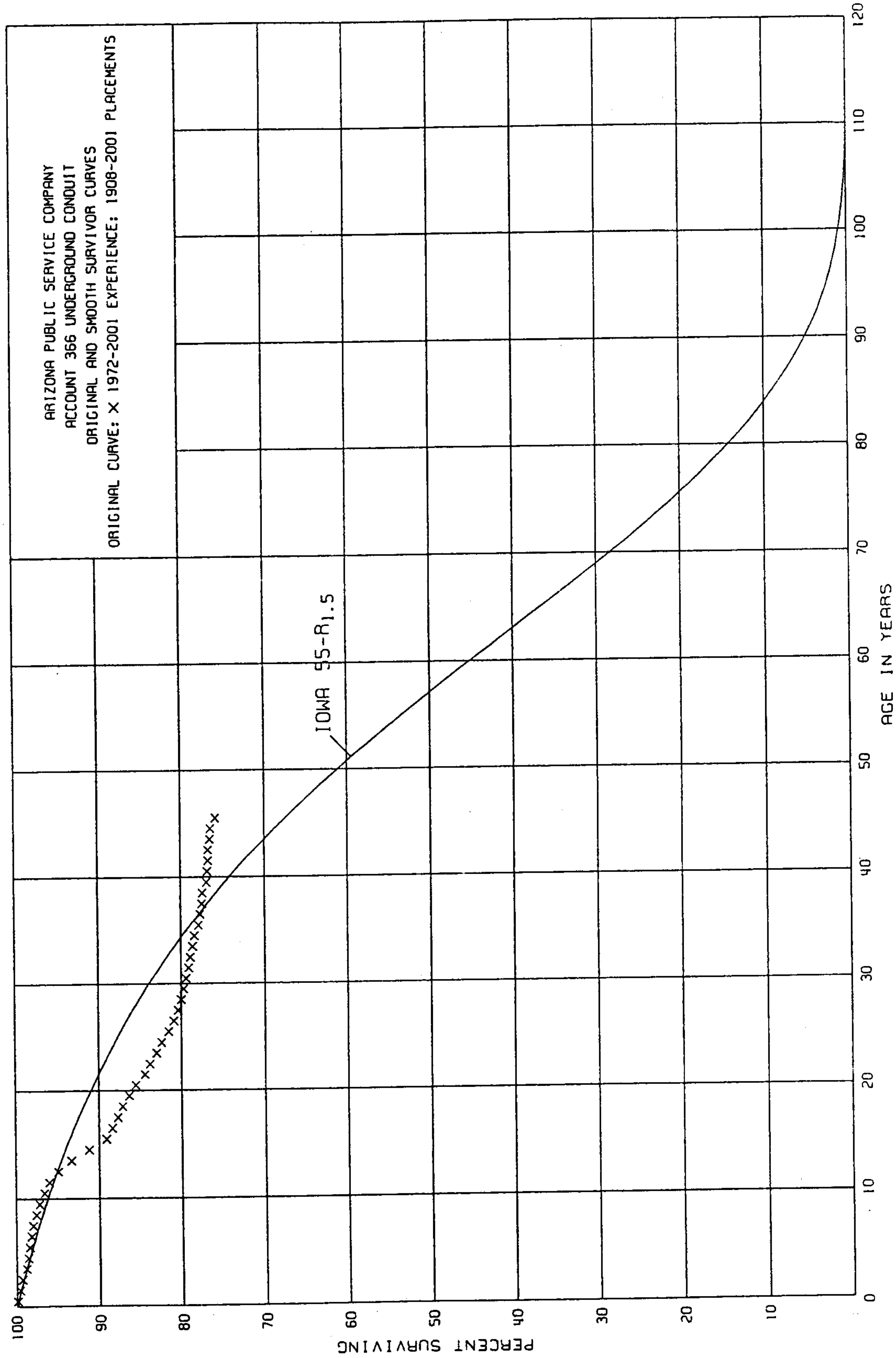
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1915-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,368,138	131,680	0.0157	0.9843	64.57
40.5	7,322,220	117,299	0.0160	0.9840	63.56
41.5	6,008,525	73,160	0.0122	0.9878	62.54
42.5	5,950,008	67,548	0.0114	0.9886	61.78
43.5	5,407,719	92,900	0.0172	0.9828	61.08
44.5	4,300,559	58,267	0.0135	0.9865	60.03
45.5	3,696,885	63,208	0.0171	0.9829	59.22
46.5	3,093,092	50,975	0.0165	0.9835	58.21
47.5	3,042,949	88,212	0.0290	0.9710	57.25
48.5	2,954,737	39,786	0.0135	0.9865	55.59
49.5	2,914,951	22,417	0.0077	0.9923	54.84
50.5	2,892,999	9,338	0.0032	0.9968	54.42
51.5	2,883,661	29,334	0.0102	0.9898	54.25
52.5	708	46	0.0650	0.9350	53.70
53.5	677	72	0.1064	0.8936	50.21
54.5	779	343	0.4403	0.5597	44.87
55.5	472	472	1.0000	0.0000	25.11
56.5					0.00
57.5	17	17	1.0000		
58.5					
59.5					
60.5	190		0.0000		
61.5	3,557	3,229	0.9078		
62.5	368		0.0000		
63.5	368	40	0.1087		
64.5	1,701	328	0.1928		
65.5	2,583	1,142	0.4421		
66.5	1,441		0.0000		
67.5	1,460	1,441	0.9870		
68.5	19	19	1.0000		
69.5	24	24	1.0000		
70.5					
71.5					
72.5					
73.5					
74.5					
75.5					
76.5					
77.5	36		0.0000		
78.5	36		0.0000		


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 366 UNDERGROUND CONDUIT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1972-2001 EXPERIENCE; 1908-2001 PLACEMENTS
IOWA 55-R1.5
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 366 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1908-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	387,596,920	421,701	0.0011	0.9989	100.00
0.5	366,031,434	1,218,352	0.0033	0.9967	99.89
1.5	342,315,058	985,589	0.0029	0.9971	99.56
2.5	315,641,697	1,522,658	0.0048	0.9952	99.27
3.5	279,995,934	452,787	0.0016	0.9984	98.79
4.5	248,933,463	495,046	0.0020	0.9980	98.63
5.5	208,517,962	455,208	0.0022	0.9978	98.43
6.5	178,210,460	426,608	0.0024	0.9976	98.21
7.5	141,817,235	518,998	0.0037	0.9963	97.97
8.5	83,128,115	385,736	0.0046	0.9954	97.61
9.5	75,025,439	453,446	0.0060	0.9940	97.16
10.5	61,844,478	390,577	0.0063	0.9937	96.58
11.5	47,199,200	513,614	0.0109	0.9891	95.97
12.5	41,698,898	716,324	0.0172	0.9828	94.92
13.5	32,049,449	710,617	0.0222	0.9778	93.29
14.5	27,796,576	653,240	0.0235	0.9765	91.22
15.5	24,647,603	200,425	0.0081	0.9919	89.08
16.5	23,754,152	181,625	0.0076	0.9924	88.36
17.5	21,734,445	155,778	0.0072	0.9928	87.69
18.5	19,317,915	160,134	0.0083	0.9917	87.06
19.5	16,863,697	162,530	0.0096	0.9904	86.34
20.5	14,547,334	183,148	0.0126	0.9874	85.51
21.5	11,716,676	91,476	0.0078	0.9922	84.43
22.5	10,394,393	92,360	0.0089	0.9911	83.77
23.5	8,435,989	67,576	0.0080	0.9920	83.02
24.5	8,026,063	82,367	0.0103	0.9897	82.36
25.5	8,074,618	62,361	0.0077	0.9923	81.51
26.5	7,194,354	41,967	0.0058	0.9942	80.88
27.5	6,289,634	34,671	0.0055	0.9945	80.41
28.5	5,995,739	20,467	0.0034	0.9966	79.97
29.5	5,357,273	18,992	0.0035	0.9965	79.70
30.5	4,446,730	17,803	0.0040	0.9960	79.42
31.5	4,219,878	11,015	0.0026	0.9974	79.10
32.5	3,915,913	15,342	0.0039	0.9961	78.89
33.5	3,121,257	8,779	0.0028	0.9972	78.58
34.5	2,278,994	13,188	0.0058	0.9942	78.36
35.5	2,135,709	4,745	0.0022	0.9978	77.91
36.5	2,600,956	8,038	0.0031	0.9969	77.74
37.5	1,942,107	3,408	0.0018	0.9982	77.50
38.5	1,770,454	11,571	0.0065	0.9935	77.36

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 366 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1908-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,704,294	1,944	0.0011	0.9989	76.86
40.5	734,985	618	0.0008	0.9992	76.78
41.5	715,027	33	0.0000	1.0000	76.72
42.5	715,248	1,724	0.0024	0.9976	76.72
43.5	700,476	1,100	0.0016	0.9984	76.54
44.5	681,964	5,787	0.0085	0.9915	76.42
45.5	5,297	64	0.0121	0.9879	75.77
46.5	5,233	140	0.0268	0.9732	74.85
47.5	5,093	47	0.0092	0.9908	72.84
48.5	5,046	36	0.0071	0.9929	72.17
49.5	5,010	62	0.0124	0.9876	71.66
50.5	4,948	42	0.0085	0.9915	70.77
51.5	4,906	198	0.0404	0.9596	70.17
52.5					67.34
53.5					
54.5					
55.5					
56.5					
57.5					
58.5					
59.5					
60.5					
61.5					
62.5					
63.5					
64.5					
65.5					
66.5					
67.5					
68.5					
69.5					
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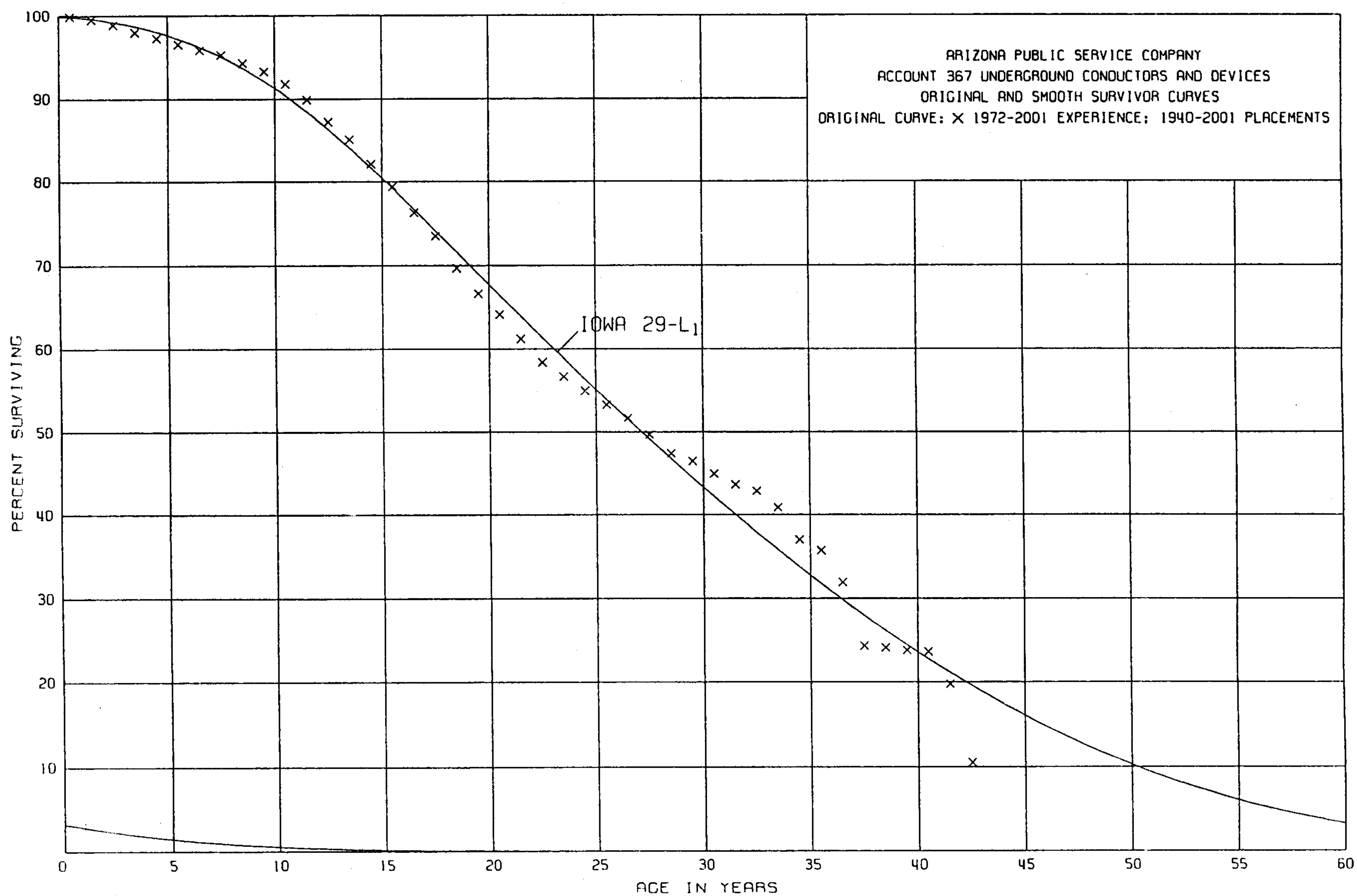
74.5					
75.5					
76.5					
77.5					
78.5					


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1972-2001 EXPERIENCE; 1940-2001 PLACEMENTS
IOWA 29-L1
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30
35
40
45
50
55
60

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1940-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	876,284,012	722,739	0.0008	0.9992	100.00
0.5	826,753,572	3,537,174	0.0043	0.9957	99.92
1.5	756,425,408	4,834,281	0.0064	0.9936	99.49
2.5	702,641,107	6,219,588	0.0089	0.9911	98.85
3.5	624,803,234	4,030,394	0.0065	0.9935	97.97
4.5	573,423,507	4,562,444	0.0080	0.9920	97.33
5.5	522,560,698	3,641,348	0.0070	0.9930	96.55
6.5	473,417,534	2,604,433	0.0055	0.9945	95.87
7.5	441,943,847	4,785,505	0.0108	0.9892	95.34
8.5	402,442,922	4,177,513	0.0104	0.9896	94.31
9.5	352,124,730	5,844,161	0.0166	0.9834	93.33
10.5	316,232,442	6,316,870	0.0200	0.9800	91.78
11.5	262,661,787	8,031,631	0.0306	0.9694	89.94
12.5	213,882,177	5,178,974	0.0242	0.9758	87.19
13.5	170,959,791	5,862,836	0.0343	0.9657	85.08
14.5	140,245,306	4,665,047	0.0333	0.9667	82.16
15.5	119,589,944	4,688,010	0.0392	0.9608	79.42
16.5	95,875,553	3,552,130	0.0370	0.9630	76.31
17.5	80,832,904	4,148,953	0.0513	0.9487	73.49
18.5	68,325,741	3,084,588	0.0451	0.9549	69.72
19.5	54,740,754	2,007,801	0.0367	0.9633	66.58
20.5	41,648,606	1,906,300	0.0458	0.9542	64.14
21.5	30,967,227	1,439,707	0.0465	0.9535	61.20
22.5	29,719,479	847,561	0.0285	0.9715	58.35
23.5	25,111,726	731,069	0.0291	0.9709	56.69
24.5	23,931,316	761,995	0.0318	0.9682	55.04
25.5	24,508,389	734,459	0.0300	0.9700	53.29
26.5	21,764,519	825,899	0.0379	0.9621	51.69
27.5	21,429,433	998,417	0.0466	0.9534	49.73
28.5	22,102,703	443,786	0.0201	0.9799	47.41
29.5	21,031,634	642,292	0.0305	0.9695	46.46
30.5	19,539,231	587,074	0.0300	0.9700	45.04
31.5	20,989,042	362,802	0.0173	0.9827	43.69
32.5	19,744,916	951,329	0.0482	0.9518	42.93
33.5	16,722,784	1,590,029	0.0951	0.9049	40.86
34.5	12,310,074	438,612	0.0356	0.9644	36.97
35.5	10,945,048	1,162,964	0.1063	0.8937	35.65
36.5	11,767,472	2,781,056	0.2363	0.7637	31.86
37.5	7,601,852	64,440	0.0085	0.9915	24.33
38.5	7,179,864	99,096	0.0138	0.9862	24.12

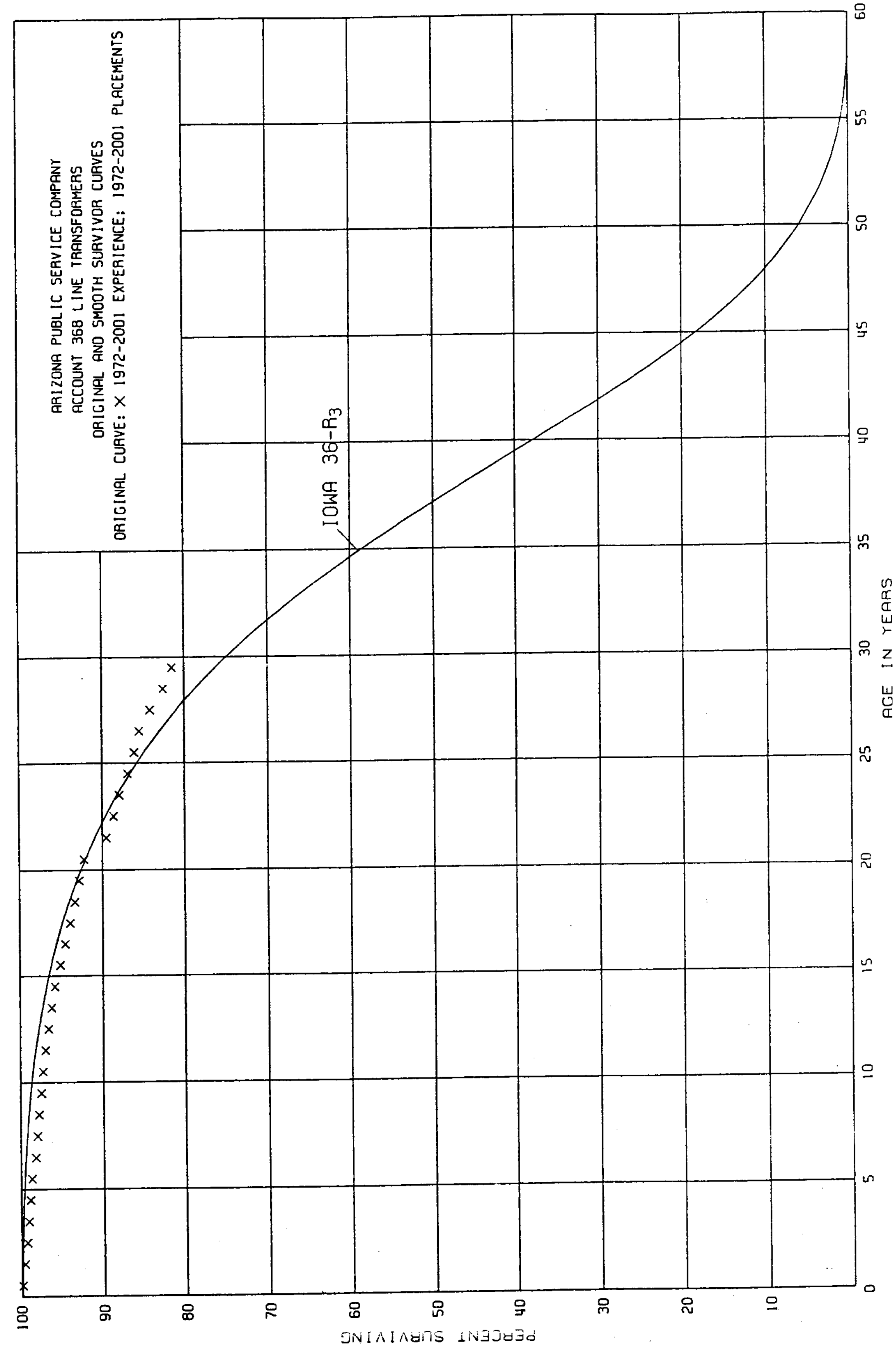
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1940-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	7,075,411	65,899	0.0093	0.9907	23.79
40.5	4,074,677	649,644	0.1594	0.8406	23.57
41.5	3,374,651	1,587,494	0.4704	0.5296	19.81
42.5	1,797,391	28,270	0.0157	0.9843	10.49
43.5	1,714,852	22,438	0.0131	0.9869	10.33
44.5	1,692,414	30,389	0.0180	0.9820	10.19
45.5	10,939	1,409	0.1288	0.8712	10.01
46.5	9,610	357	0.0371	0.9629	8.72
47.5	9,253	8,564	0.9255	0.0745	8.40
48.5	689	92	0.1335	0.8665	0.63
49.5	597	522	0.8744	0.1256	0.55
50.5	75	75	1.0000	0.0000	0.07
51.5					0.00


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 368 LINE TRANSFORMERS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1972-2001 EXPERIENCE; 1972-2001 PLACEMENTS
IOWA 36-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30
35
40
45
50
55
60

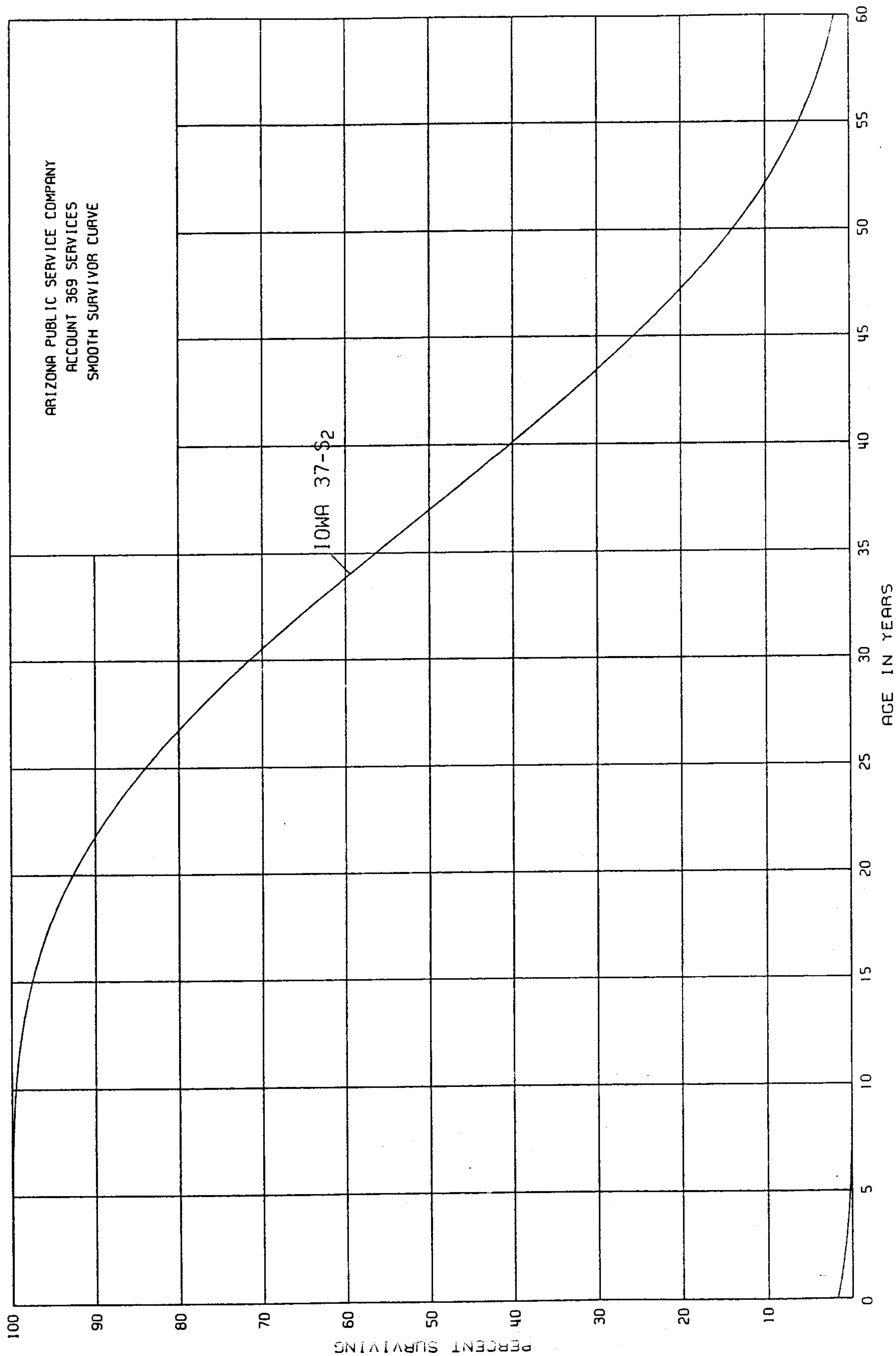
ARIZONA PUBLIC SERVICE COMPANY

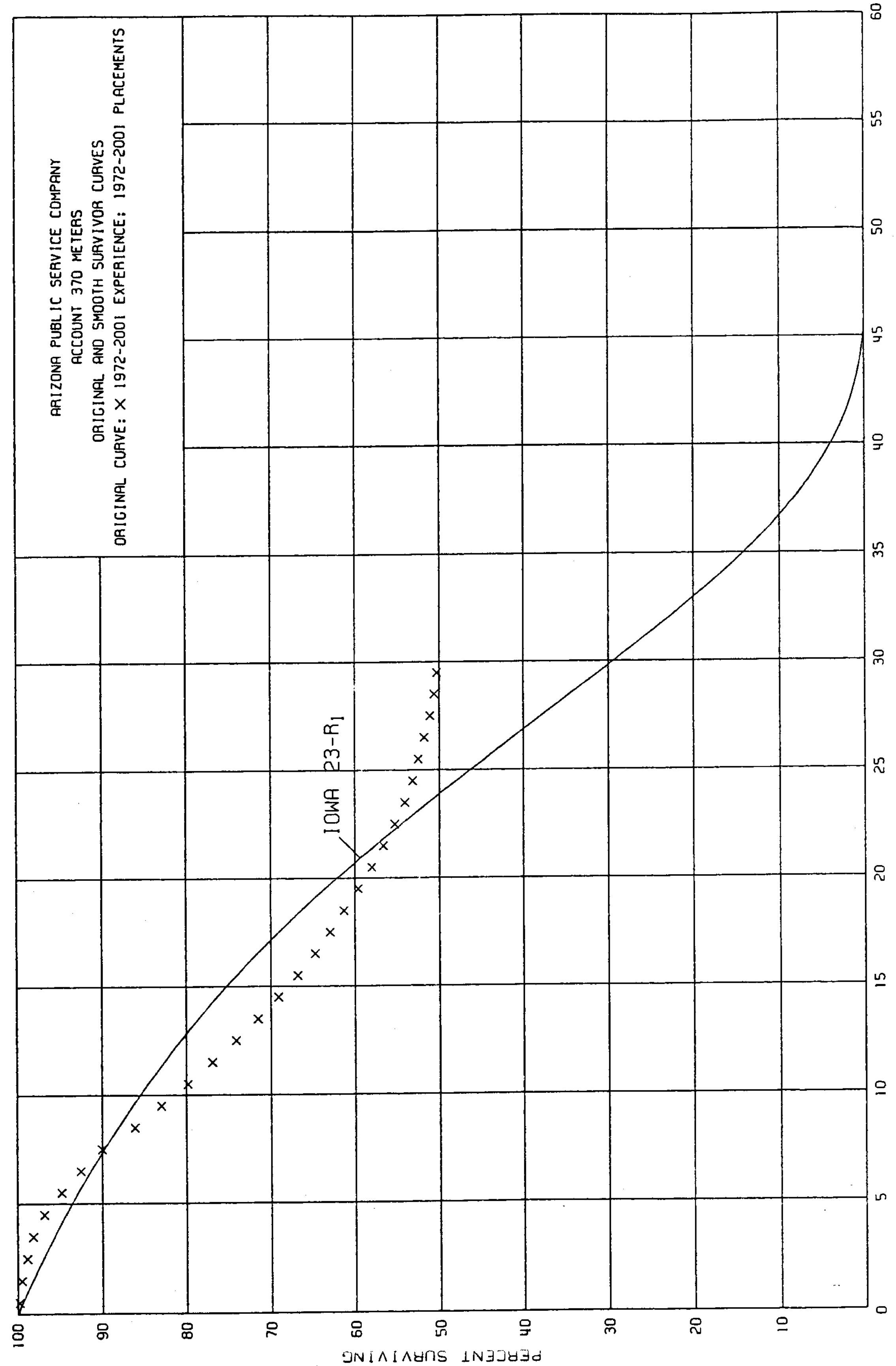
ACCOUNT 368 LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1972-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	409,556,128	483,755	0.0012	0.9988	100.00
0.5	390,218,638	1,200,766	0.0031	0.9969	99.88
1.5	367,685,199	861,295	0.0023	0.9977	99.57
2.5	350,982,330	755,933	0.0022	0.9978	99.34
3.5	312,140,355	768,355	0.0025	0.9975	99.12
4.5	298,452,409	633,025	0.0021	0.9979	98.87
5.5	282,799,624	1,223,347	0.0043	0.9957	98.66
6.5	270,084,291	654,473	0.0024	0.9976	98.24
7.5	274,645,188	727,375	0.0026	0.9974	98.00
8.5	265,123,356	633,902	0.0024	0.9976	97.75
9.5	254,373,710	657,468	0.0026	0.9974	97.52
10.5	248,753,773	722,947	0.0029	0.9971	97.27
11.5	234,213,940	859,337	0.0037	0.9963	96.99
12.5	214,743,174	980,429	0.0046	0.9954	96.63
13.5	196,944,893	879,530	0.0045	0.9955	96.19
14.5	180,289,967	1,173,383	0.0065	0.9935	95.76
15.5	158,198,520	991,364	0.0063	0.9937	95.14
16.5	134,793,615	866,706	0.0064	0.9936	94.54
17.5	110,041,250	700,122	0.0064	0.9936	93.93
18.5	95,881,610	503,952	0.0053	0.9947	93.33
19.5	81,829,313	566,754	0.0069	0.9931	92.84
20.5	60,458,630	1,803,366	0.0298	0.9702	92.20
21.5	47,625,668	457,337	0.0096	0.9904	89.45
22.5	36,588,981	306,847	0.0084	0.9916	88.59
23.5	27,305,045	307,146	0.0112	0.9888	87.85
24.5	20,576,219	188,658	0.0092	0.9908	86.87
25.5	17,296,179	116,501	0.0067	0.9933	86.07
26.5	13,096,021	204,520	0.0156	0.9844	85.49
27.5	8,194,985	148,010	0.0181	0.9819	84.16
28.5	3,257,153	45,533	0.0140	0.9860	82.64
29.5					81.48


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 369 SERVICES
SMOOTH SURVIVOR CURVE
IOWA 37-S2
AGE IN YEARS
PERCENT SURVIVING
0
5
10
15
20
25
30
35
40
45
50
55
60
100
90
80
70
60
50
40
30
20
10


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 370 METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1972-2001 EXPERIENCE; 1972-2001 PLACEMENTS
IOWA 23-R1
AGE IN YEARS
PERCENT SURVIVING
0
5
10
15
20
25
30
35
40
45
50
55
60
100
90
80
70
60
50
40
30
20
10

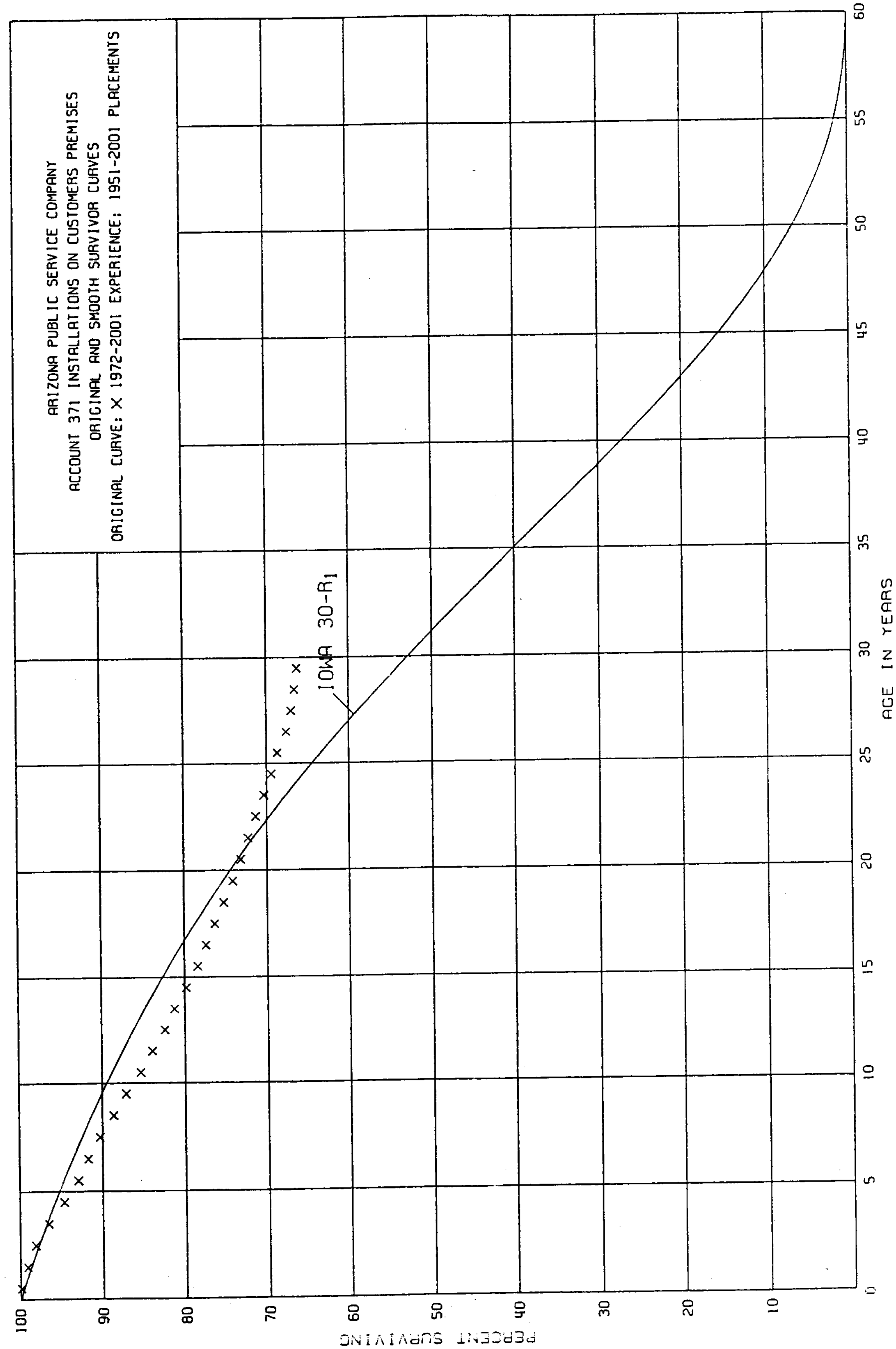
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 370 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1972-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	171,380,365	289,831	0.0017	0.9983	100.00
0.5	167,447,246	585,614	0.0035	0.9965	99.83
1.5	160,251,591	867,099	0.0054	0.9946	99.48
2.5	154,415,917	1,181,538	0.0077	0.9923	98.94
3.5	139,853,168	1,811,238	0.0130	0.9870	98.18
4.5	138,376,708	2,975,787	0.0215	0.9785	96.90
5.5	130,673,277	3,141,897	0.0240	0.9760	94.82
6.5	118,341,757	3,277,562	0.0277	0.9723	92.54
7.5	100,253,207	4,292,260	0.0428	0.9572	89.98
8.5	88,394,041	3,232,030	0.0366	0.9634	86.13
9.5	67,046,287	2,580,629	0.0385	0.9615	82.98
10.5	59,043,856	2,153,575	0.0365	0.9635	79.79
11.5	50,703,081	1,860,819	0.0367	0.9633	76.88
12.5	41,048,837	1,417,294	0.0345	0.9655	74.06
13.5	33,937,772	1,130,152	0.0333	0.9667	71.50
14.5	26,789,449	886,027	0.0331	0.9669	69.12
15.5	22,502,412	714,854	0.0318	0.9682	66.83
16.5	18,212,515	511,904	0.0281	0.9719	64.70
17.5	14,300,708	359,207	0.0251	0.9749	62.88
18.5	12,868,692	362,554	0.0282	0.9718	61.30
19.5	11,839,624	305,175	0.0258	0.9742	59.57
20.5	9,863,168	245,276	0.0249	0.9751	58.03
21.5	7,625,230	170,695	0.0224	0.9776	56.59
22.5	5,922,251	127,693	0.0216	0.9784	55.32
23.5	4,805,834	82,836	0.0172	0.9828	54.13
24.5	3,485,345	49,079	0.0141	0.9859	53.20
25.5	2,988,744	40,080	0.0134	0.9866	52.45
26.5	2,598,288	32,474	0.0125	0.9875	51.75
27.5	1,633,577	14,733	0.0090	0.9910	51.10
28.5	742,234	5,113	0.0069	0.9931	50.64
29.5					50.29



ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 371 INSTALLATIONS ON CUSTOMERS PREMISES
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1972-2001 EXPERIENCE; 1951-2001 PLACEMENTS
IOWA 30-R1
AGE IN YEARS
PERCENT SURVIVING
0
5
10
15
20
25
30
35
40
45
50
55
60
100
90
80
70
60
50
40
30
20
10

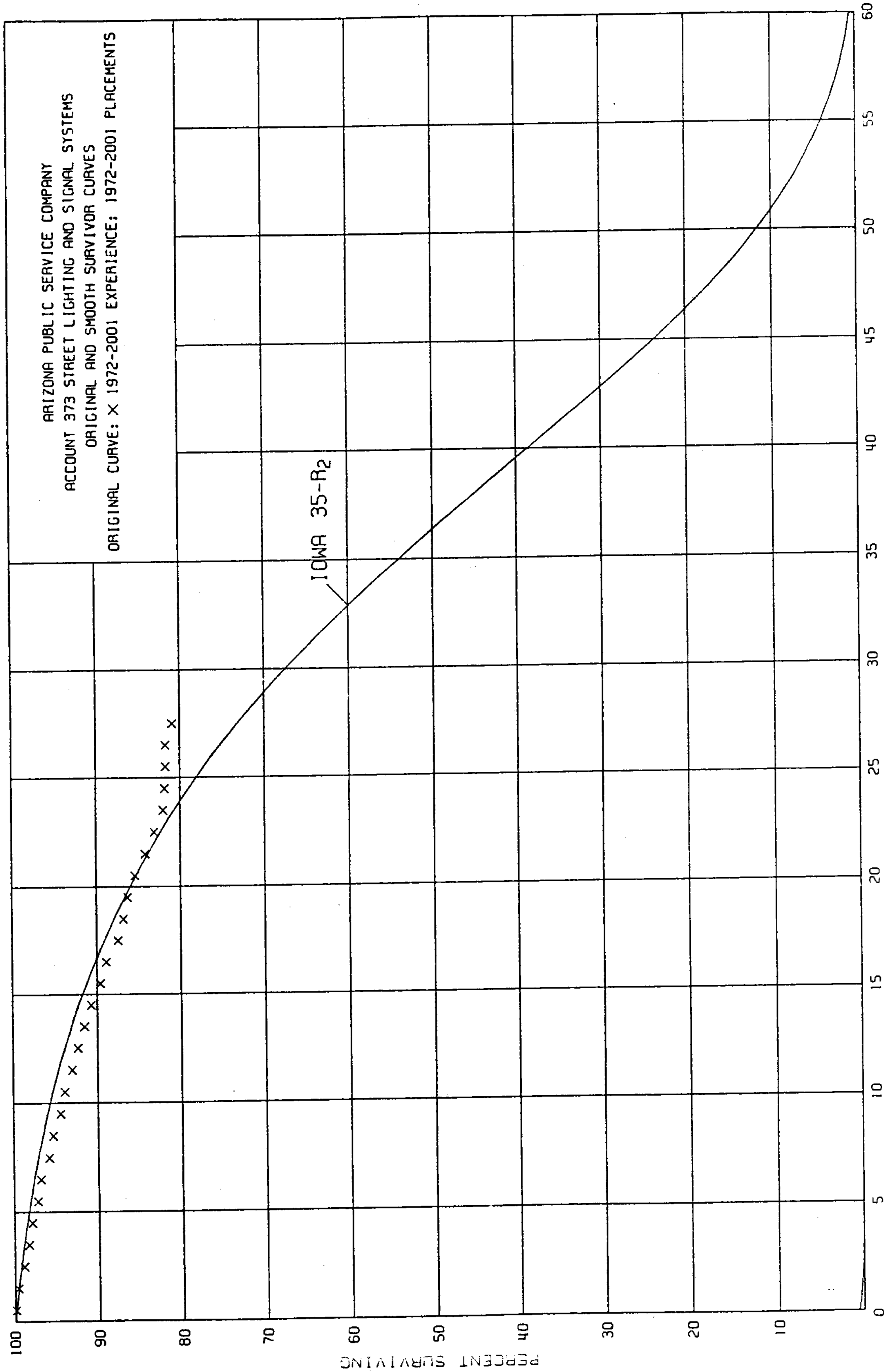
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1951-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	24,671,248	32,306	0.0013	0.9987	100.00
0.5	24,023,847	188,156	0.0078	0.9922	99.87
1.5	22,305,295	224,931	0.0101	0.9899	99.09
2.5	21,361,416	338,732	0.0159	0.9841	98.09
3.5	20,240,250	412,775	0.0204	0.9796	96.53
4.5	18,552,871	326,158	0.0176	0.9824	94.56
5.5	16,702,405	218,915	0.0131	0.9869	92.90
6.5	15,539,661	238,951	0.0154	0.9846	91.68
7.5	13,821,733	255,437	0.0185	0.9815	90.27
8.5	12,007,759	208,793	0.0174	0.9826	88.60
9.5	11,036,857	217,675	0.0197	0.9803	87.06
10.5	9,592,889	167,221	0.0174	0.9826	85.34
11.5	9,067,270	155,378	0.0171	0.9829	83.86
12.5	7,936,187	117,299	0.0148	0.9852	82.43
13.5	6,976,472	123,526	0.0177	0.9823	81.21
14.5	6,546,715	109,537	0.0167	0.9833	79.77
15.5	6,147,033	77,948	0.0127	0.9873	78.44
16.5	5,419,353	82,991	0.0153	0.9847	77.44
17.5	5,215,028	72,774	0.0140	0.9860	76.26
18.5	4,835,135	70,142	0.0145	0.9855	75.19
19.5	4,598,392	59,356	0.0129	0.9871	74.10
20.5	3,942,379	53,735	0.0136	0.9864	73.14
21.5	3,549,030	39,881	0.0112	0.9888	72.15
22.5	3,209,124	47,245	0.0147	0.9853	71.34
23.5	3,066,294	39,868	0.0130	0.9870	70.29
24.5	2,977,216	27,840	0.0094	0.9906	69.38
25.5	2,993,994	50,398	0.0168	0.9832	68.73
26.5	2,738,115	22,239	0.0081	0.9919	67.58
27.5	3,061,705	19,088	0.0062	0.9938	67.03
28.5	2,835,803	15,137	0.0053	0.9947	66.61
29.5	2,515,823	16,424	0.0065	0.9935	66.26
30.5	2,220,411	11,115	0.0050	0.9950	65.83
31.5	2,128,056	19,686	0.0093	0.9907	65.50
32.5	1,768,363	9,240	0.0052	0.9948	64.89
33.5	1,569,010	9,062	0.0058	0.9942	64.55
34.5	1,227,674	5,207	0.0042	0.9958	64.18
35.5	1,007,392	2,459	0.0024	0.9976	63.91
36.5	1,160	200	0.1724	0.8276	63.76
37.5	1,469		0.0000	1.0000	52.77
38.5	1,531	1,138	0.7433	0.2567	52.77


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1972-2001 EXPERIENCE; 1972-2001 PLACEMENTS
IOWA 35-R2
AGE IN YEARS
PERCENT SURVIVING
0
5
10
15
20
25
30
35
40
45
50
55
60
100
90
80
70
60
50
40
30
20
10

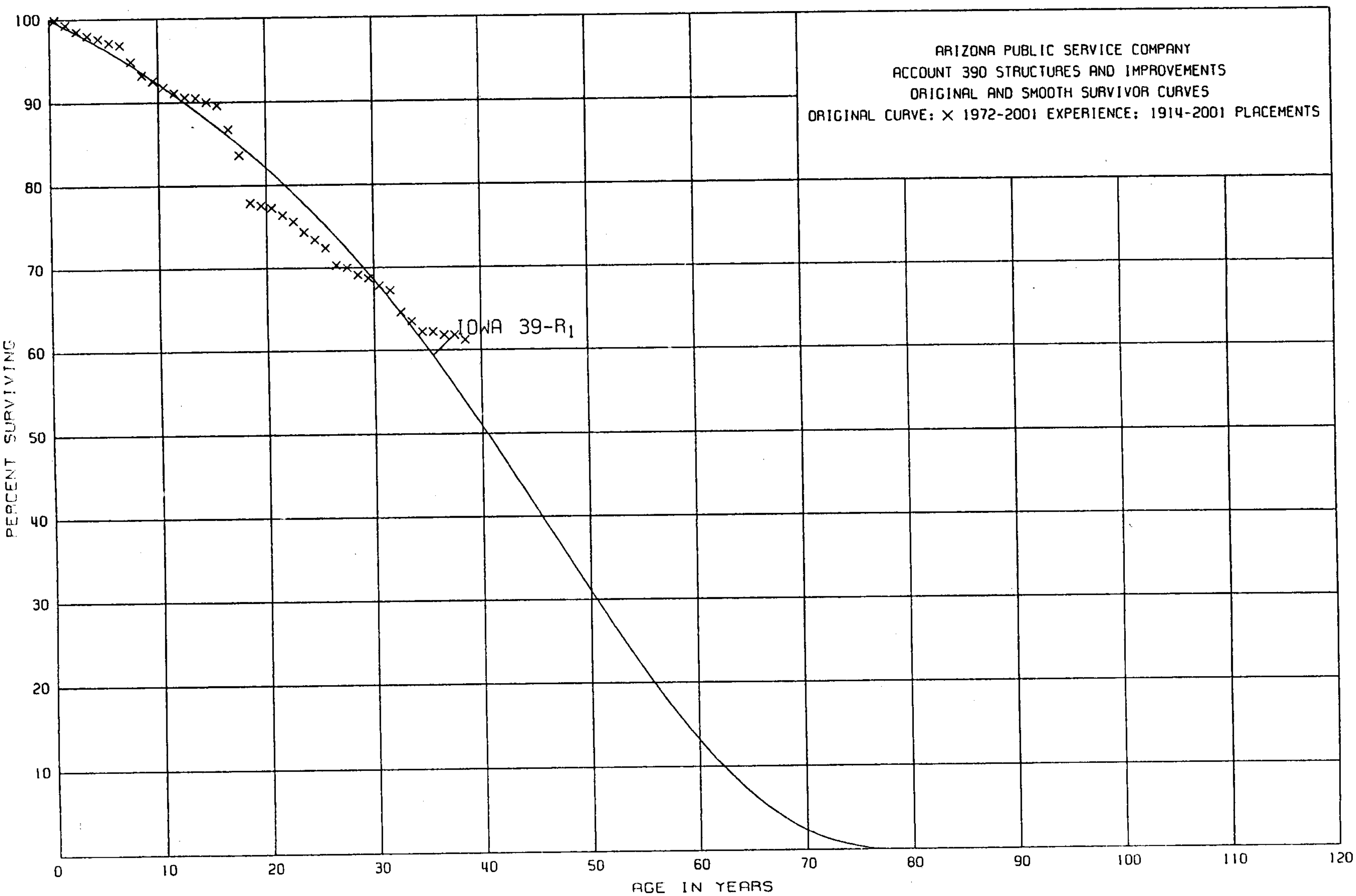
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1972-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	89,131,201	42,460	0.0005	0.9995	100.00
0.5	85,324,632	314,888	0.0037	0.9963	99.95
1.5	84,687,663	551,919	0.0065	0.9935	99.58
2.5	78,455,755	545,127	0.0069	0.9931	98.93
3.5	70,363,140	262,948	0.0037	0.9963	98.25
4.5	64,073,407	426,834	0.0067	0.9933	97.89
5.5	55,077,558	250,129	0.0045	0.9955	97.23
6.5	46,588,158	490,023	0.0105	0.9895	96.79
7.5	39,570,710	214,049	0.0054	0.9946	95.77
8.5	33,192,144	284,370	0.0086	0.9914	95.25
9.5	31,540,940	189,643	0.0060	0.9940	94.43
10.5	25,425,774	231,617	0.0091	0.9909	93.86
11.5	22,105,553	163,189	0.0074	0.9926	93.01
12.5	16,773,375	152,492	0.0091	0.9909	92.32
13.5	14,321,601	125,575	0.0088	0.9912	91.48
14.5	11,064,570	130,496	0.0118	0.9882	90.67
15.5	10,072,303	81,171	0.0081	0.9919	89.60
16.5	8,975,449	142,844	0.0159	0.9841	88.87
17.5	8,094,826	61,850	0.0076	0.9924	87.46
18.5	6,361,242	36,646	0.0058	0.9942	86.80
19.5	5,491,831	57,921	0.0105	0.9895	86.30
20.5	4,123,378	57,244	0.0139	0.9861	85.39
21.5	3,441,063	45,089	0.0131	0.9869	84.20
22.5	2,786,888	37,441	0.0134	0.9866	83.10
23.5	1,959,515	5,540	0.0028	0.9972	81.99
24.5	1,569,268	1,356	0.0009	0.9991	81.76
25.5	1,209,232	462	0.0004	0.9996	81.69
26.5	897,144	8,365	0.0093	0.9907	81.66
27.5	564,386	4,544	0.0081	0.9919	80.90
28.5	209,937	884	0.0042	0.9958	80.24
29.5					79.90



ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 390 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1972-2001 EXPERIENCE: 1914-2001 PLACEMENTS
IOWA 39-R1
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

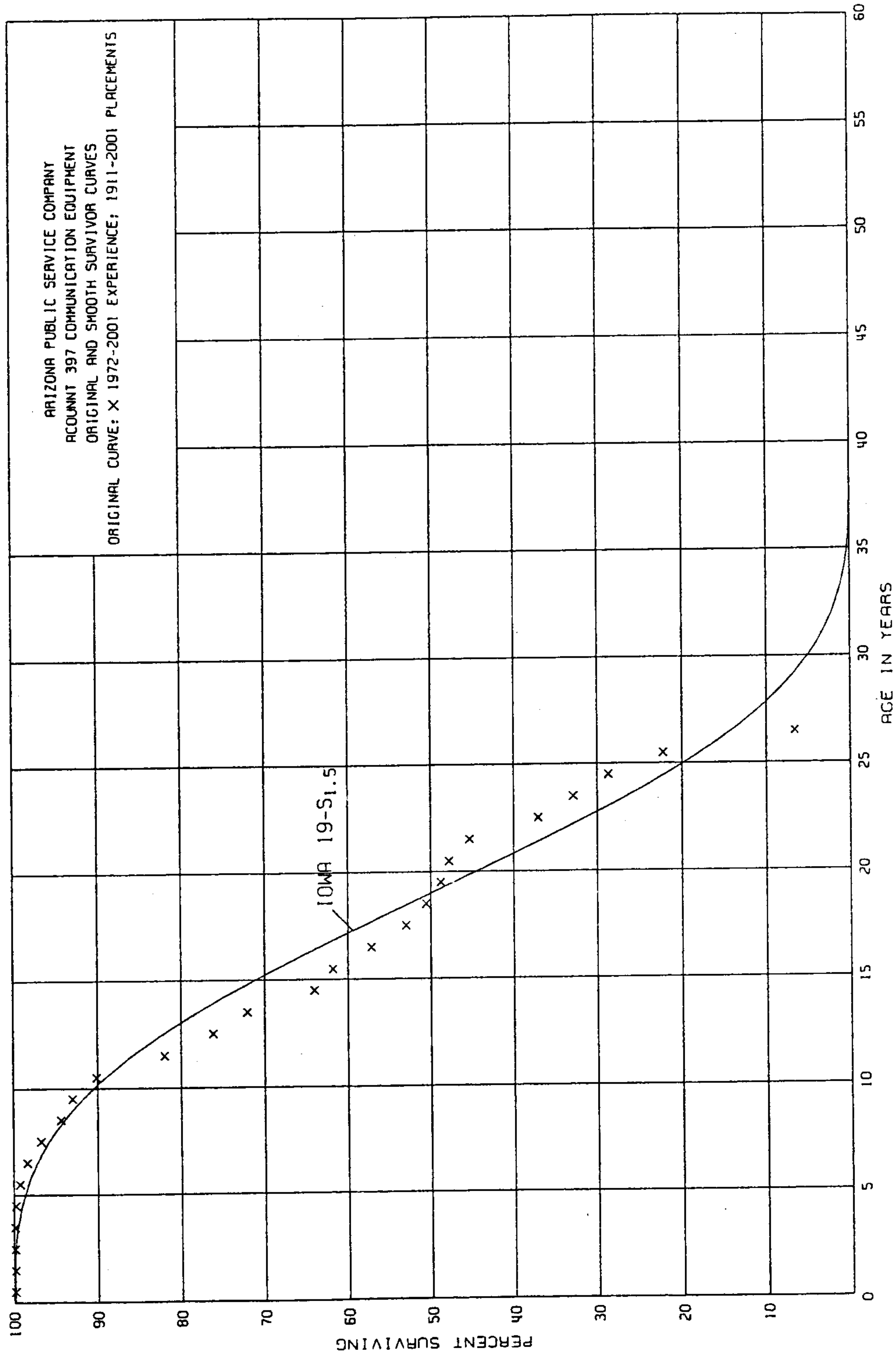
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1914-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	92,892,264	43,983	0.0005	0.9995	100.00
0.5	94,523,118	656,714	0.0069	0.9931	99.95
1.5	93,764,375	727,700	0.0078	0.9922	99.26
2.5	93,307,523	432,280	0.0046	0.9954	98.49
3.5	86,288,480	367,348	0.0043	0.9957	98.04
4.5	87,355,391	466,745	0.0053	0.9947	97.62
5.5	75,872,877	269,125	0.0035	0.9965	97.10
6.5	74,646,924	1,523,616	0.0204	0.9796	96.76
7.5	70,323,580	1,153,390	0.0164	0.9836	94.79
8.5	69,688,415	546,748	0.0078	0.9922	93.24
9.5	67,850,038	535,768	0.0079	0.9921	92.51
10.5	59,934,599	463,170	0.0077	0.9923	91.78
11.5	57,647,623	303,057	0.0053	0.9947	91.07
12.5	61,827,132	96,191	0.0016	0.9984	90.59
13.5	51,678,469	282,821	0.0055	0.9945	90.45
14.5	46,343,248	174,499	0.0038	0.9962	89.95
15.5	36,738,087	1,207,019	0.0329	0.9671	89.61
16.5	28,282,040	998,553	0.0353	0.9647	86.66
17.5	25,627,800	1,763,828	0.0688	0.9312	83.60
18.5	23,118,190	89,748	0.0039	0.9961	77.85
19.5	19,567,474	53,758	0.0027	0.9973	77.55
20.5	19,462,739	239,006	0.0123	0.9877	77.34
21.5	11,292,736	117,207	0.0104	0.9896	76.39
22.5	7,985,579	140,264	0.0176	0.9824	75.60
23.5	7,480,489	85,065	0.0114	0.9886	74.27
24.5	7,270,176	105,216	0.0145	0.9855	73.42
25.5	6,870,763	198,536	0.0289	0.9711	72.36
26.5	6,293,136	24,178	0.0038	0.9962	70.27
27.5	5,552,907	72,063	0.0130	0.9870	70.00
28.5	5,271,555	30,232	0.0057	0.9943	69.09
29.5	6,465,227	88,712	0.0137	0.9863	68.70
30.5	7,402,688	59,551	0.0080	0.9920	67.76
31.5	7,424,520	288,151	0.0388	0.9612	67.22
32.5	6,697,769	117,374	0.0175	0.9825	64.61
33.5	6,457,574	131,006	0.0203	0.9797	63.48
34.5	6,224,864	623	0.0001	0.9999	62.19
35.5	6,059,235	32,478	0.0054	0.9946	62.18
36.5	5,985,690		0.0000	1.0000	61.84
37.5	5,418,693	54,049	0.0100	0.9900	61.84
38.5	1,805,012		0.0000	1.0000	61.22


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 397 COMMUNICATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1972-2001 EXPERIENCE; 1911-2001 PLACEMENTS
IOWA 19-S1.5
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30
35
40
45
50
55
60

ARIZONA PUBLIC SERVICE COMPANY

ACOUNNT 397 COMMUNICATION EQUIPMENT

ORIGINAL LIFE TABLE

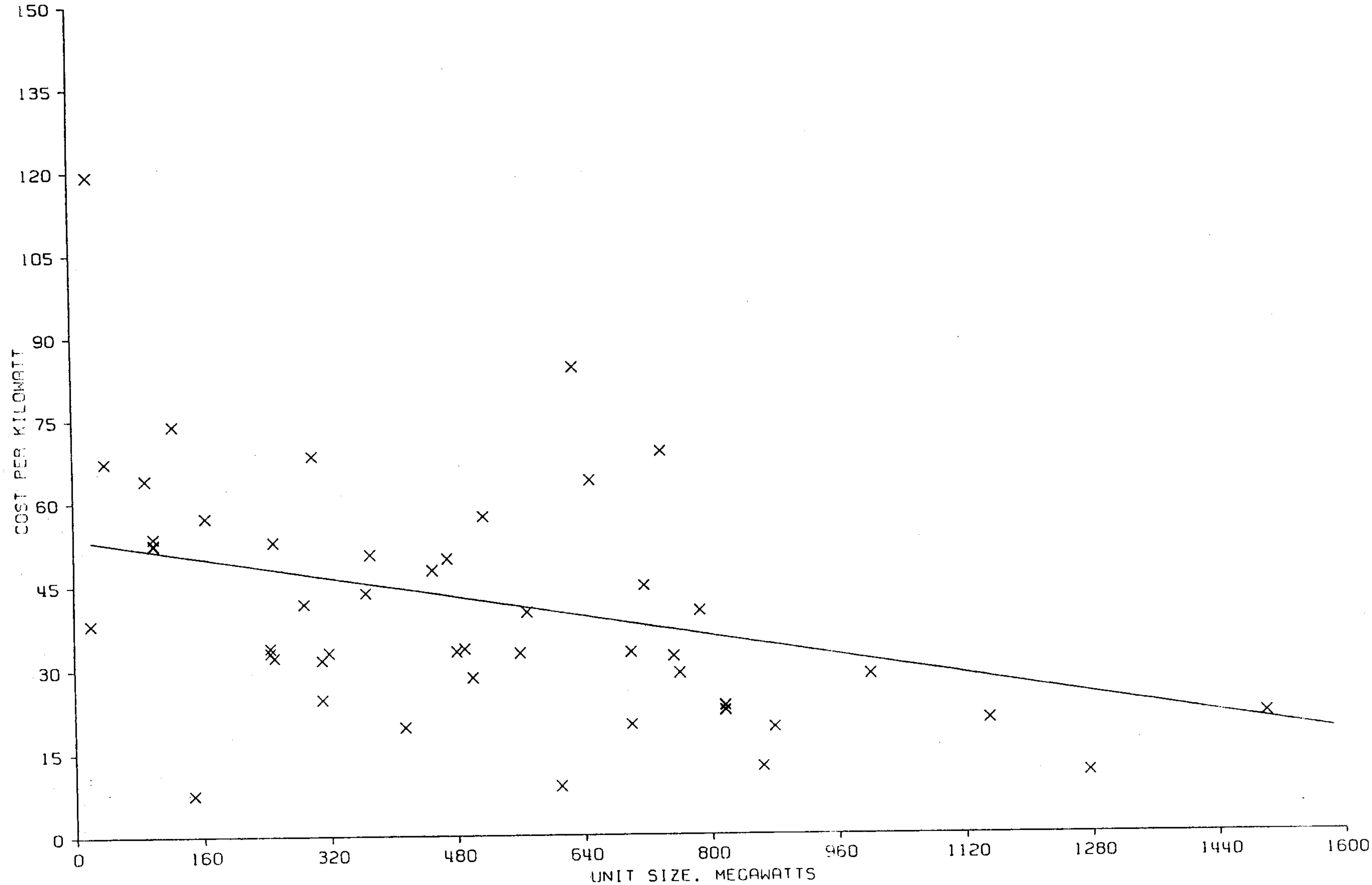
PLACEMENT BAND 1911-2001 EXPERIENCE BAND 1972-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	111,341,395	15,632	0.0001	0.9999	100.00
0.5	113,495,930	67,997	0.0006	0.9994	99.99
1.5	106,857,796	54,014	0.0005	0.9995	99.93
2.5	97,800,616	30,758	0.0003	0.9997	99.88
3.5	93,304,203	79,786	0.0009	0.9991	99.85
4.5	86,361,681	388,963	0.0045	0.9955	99.76
5.5	78,128,541	735,316	0.0094	0.9906	99.31
6.5	75,650,869	1,258,978	0.0166	0.9834	98.38
7.5	69,997,294	1,720,145	0.0246	0.9754	96.75
8.5	67,948,776	991,574	0.0146	0.9854	94.37
9.5	63,140,411	1,970,707	0.0312	0.9688	92.99
10.5	56,825,602	5,095,257	0.0897	0.9103	90.09
11.5	41,763,827	3,035,451	0.0727	0.9273	82.01
12.5	35,052,261	1,827,478	0.0521	0.9479	76.05
13.5	32,633,330	3,673,741	0.1126	0.8874	72.09
14.5	27,586,977	954,729	0.0346	0.9654	63.97
15.5	20,418,164	1,524,797	0.0747	0.9253	61.76
16.5	17,884,676	1,304,589	0.0729	0.9271	57.15
17.5	16,027,829	716,226	0.0447	0.9553	52.98
18.5	15,083,269	548,432	0.0364	0.9636	50.61
19.5	12,898,556	251,026	0.0195	0.9805	48.77
20.5	12,408,395	659,891	0.0532	0.9468	47.82
21.5	9,781,996	1,794,696	0.1835	0.8165	45.28
22.5	7,805,917	882,071	0.1130	0.8870	36.97
23.5	6,351,972	792,150	0.1247	0.8753	32.79
24.5	4,825,454	1,101,059	0.2282	0.7718	28.70
25.5	3,571,183	2,509,049	0.7026	0.2974	22.15
26.5	1,018,352	67,279	0.0661	0.9339	6.59
27.5	1,086,668	95,255	0.0877	0.9123	6.15
28.5	974,923	21,614	0.0222	0.9778	5.61
29.5	1,039,429	101,011	0.0972	0.9028	5.49
30.5	844,560	146,086	0.1730	0.8270	4.96
31.5	701,244	230,802	0.3291	0.6709	4.10
32.5	104,678	10,005	0.0956	0.9044	2.75
33.5	92,939	90,814	0.9771	0.0229	2.49
34.5	2,125		0.0000	1.0000	0.06
35.5	2,125		0.0000	1.0000	0.06
36.5	2,125		0.0000	1.0000	0.06
37.5	2,125	2,125	1.0000	0.0000	0.06
38.5					0.00

APPENDIX B

NET SALVAGE STATISTICS

ARIZONA PUBLIC SERVICE COMPANY
DECOMMISSIONING COSTS PER KW COMPARED WITH UNIT SIZE - COAL
POLYNOMIAL REGRESSION OF DEGREE 1



ARIZONA PUBLIC SERVICE COMPANY

DECOMMISSIONING COSTS PER KW COMPARED WITH UNIT SIZE - COAL

TABLE OF RESIDUALS FOR POLYNOMIAL REGRESSION OF DEGREE 1

X VALUE	OBSERVED Y VALUE	ESTIMATED Y VALUE	RESIDUAL	RESIDUAL SQUARED
21.00	38.14	53.06	-14.92	222.5360
23.00	119.22	53.01	66.21	4383.2720
23.00	119.22	53.01	66.21	4383.2720
40.00	67.18	52.64	14.54	211.4009
40.00	67.18	52.64	14.54	211.4009
40.00	67.18	52.64	14.54	211.4009
40.00	67.18	52.64	14.54	211.4009
90.00	64.06	51.54	12.52	156.6931
100.00	52.26	51.32	.94	.8786
100.00	52.51	51.32	1.19	1.4097
100.00	53.60	51.32	2.28	5.1862
125.00	73.93	50.77	23.16	536.2176
148.00	7.56	50.27	-42.71	1824.0170
165.00	57.13	49.90	7.23	52.3429
245.00	33.05	48.14	-15.09	227.6547
245.00	33.90	48.14	-14.24	202.7271
250.00	32.20	48.03	-15.83	250.5388
250.00	52.86	48.03	4.83	23.3442
288.00	41.74	47.19	-5.45	29.7447
300.00	68.34	46.93	21.41	458.3736
310.00	24.67	46.71	-22.04	485.7933
310.00	31.73	46.71	-14.98	224.4220
319.00	33.07	46.51	-13.44	180.7160
366.00	43.67	45.48	-1.81	3.2792
372.00	50.61	45.35	5.26	27.6771
414.00	19.65	44.43	-24.78	613.8851
450.00	47.83	43.64	4.19	17.5889
469.00	49.87	43.22	6.65	44.2383
480.00	33.19	42.98	-9.79	95.7900
490.00	33.69	42.76	-9.07	82.2217
500.00	28.56	42.54	-13.98	195.3846
515.00	57.29	42.21	15.08	227.4494
560.00	32.89	41.22	-8.33	69.3940
569.00	40.15	41.02	-.87	.7615
610.00	8.96	40.12	-31.16	971.0840
630.00	84.33	39.68	44.65	1993.3560
650.00	63.76	39.24	24.52	601.0464
700.00	20.00	38.15	-18.15	329.2653
700.00	20.00	38.15	-18.15	329.2653
700.00	32.96	38.15	-5.19	26.8912
717.00	44.83	37.77	7.06	49.8109
717.00	44.83	37.77	7.06	49.8109
740.00	68.97	37.27	31.70	1005.0680
754.00	32.24	36.96	-4.72	22.2759
761.00	29.20	36.81	-7.61	57.8513
787.00	40.27	36.24	4.03	16.2812

ARIZONA PUBLIC SERVICE COMPANY

DECOMMISSIONING COSTS PER KW COMPARED WITH UNIT SIZE - COAL

TABLE OF RESIDUALS FOR POLYNOMIAL REGRESSION OF DEGREE 1

X VALUE	OBSERVED Y VALUE	ESTIMATED Y VALUE	RESIDUAL	RESIDUAL SQUARED
818.00	22.38	35.55	-13.17	173.5593
818.00	22.57	35.55	-12.98	168.5892
818.00	23.19	35.55	-12.36	152.8732
818.00	23.44	35.55	-12.11	146.7536
865.00	12.33	34.52	-22.19	492.4845
865.00	12.33	34.52	-22.19	492.4845
880.00	19.38	34.19	-14.81	219.4121
880.00	19.38	34.19	-14.81	219.4121
1001.00	28.82	31.54	-2.72	7.3723
1150.00	20.78	28.26	-7.48	55.9940
1150.00	20.78	28.26	-7.48	55.9940
1276.00	11.13	25.50	-14.37	206.3747
1500.00	21.58	20.58	1.00	1.0073
1987.00	23.34	9.88	13.46	181.1447
3145.00	24.64	-15.55	40.19	1615.2850
TOTAL			.00	25513.1600

ARIZONA PUBLIC SERVICE COMPANY

Decommissioning Costs Related to Coal-Fired Power Plants

Unit Number	Year In Service	Estimated Retirement Year	Mw	Estimated Decommissioning Costs ($/Kw)	Total Decommissioning Costs (Current $)	Aps Own	Aps Share Decommissioning Costs (Current $)	Aps Share Decommissioning Costs (Future $)	Original Cost at 12/31/01	Net Salvage
(1)	(2)	(3)	(4)	(5)	(6)=(4)*(5)	(7)	(8)=(6)*(7)	(9)a	(10)	(11)
Four Courners										
1	1963	2016	170	49.79	8,464,300	100%	8,464,300	19,326,777		
2	1963	2016	170	49.79	8,464,300	100%	8,464,300	19,326,777		
3	1964	2016	220	48.69	10,711,800	100%	10,711,800	24,458,558		
4	1969	2031	740	37.27	27,579,800	15%	4,136,970	15,825,448		
5	1970	2031	740	37.27	27,579,800	15%	4,136,970	15,825,448		
Total Four Corners					82,800,000		35,914,340	94,763,008	398,820,562	23.76%
Cholla										
1	1962	2017	110	51.10	5,621,000	100%	5,621,000	13,283,800		
2	1978	2033	235	48.36	11,364,600	100%	11,364,600	46,570,242		
3	1980	2035	245	48.14	11,794,300	100%	11,794,300	51,773,463		
Total Cholla					28,779,900		28,779,900	111,627,505	515,667,469	21.65%
Navajo										
1	1974	2026	750	37.05	27,787,500	14%	3,890,250	12,529,952		
2	1975	2026	750	37.05	27,787,500	14%	3,890,250	12,529,952		
3	1976	2026	750	37.05	27,787,500	14%	3,890,250	12,529,952		
Total Navajo					83,362,500		11,670,750	37,589,856	231,948,895	16.21%
Grand Total					194,942,400		76,364,990	243,980,369	1,146,436,926	21.28%

a Column 9 = (Column 8) x (1.035**(Estimated Retirement Year - 1992))

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1980	451,358		0		0		0
1981	15,566		0		0		0
1982	69,244		0		0		0
1983	101,400		0		0		0
1984	45,822		0		0		0
1985	112,833		0		0		0
1986	66,383		0		0		0
1987	15,260		0		0		0
1988	131,956	3,567-	3-		0	3,567	3
1989	18,310	4,833	26		0	4,833-	26-
1990	75,737	8,896	12		0	8,896-	12-
1991							
1992	291,422	34,527	12	432	0	34,095-	12-
1993	49,134	2,722	6	193	0	2,529-	5-
1994	235,796	28,201	12	8,494	4	19,707-	8-
1995	277,385	142,006	51		0	142,006-	51-
1996		75,014		953		74,061-	
1997		145,288				145,288-	
1998		52,853				52,853-	
1999		4,027				4,027-	
2000	210,080	109,661	52		0	109,661-	52-
2001	155,927	498,380	320		0	498,380-	320-
TOTAL	2,323,613	1,102,841	47	10,072	0	1,092,769-	47-

THREE-YEAR MOVING AVERAGES

80-82	178,723		0		0		0
81-83	62,070		0		0		0
82-84	72,155		0		0		0
83-85	86,685		0		0		0
84-86	75,013		0		0		0
85-87	64,825		0		0		0
86-88	71,200	1,189-	2-		0	1,189	2
87-89	55,175	422	1		0	422-	1-
88-90	75,334	3,387	4		0	3,387-	4-
89-91	31,349	4,576	15		0	4,576-	15-
90-92	122,386	14,474	12	144	0	14,330-	12-
91-93	113,519	12,416	11	208	0	12,208-	11-
92-94	192,117	21,817	11	3,040	2	18,777-	10-
93-95	187,438	57,643	31	2,896	2	54,747-	29-
94-96	171,060	81,740	48	3,149	2	78,591-	46-
95-97	92,462	120,769	131	318	0	120,451-	130-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98		91,051		318		90,733-	
97-99		67,389				67,389-	
98-00	70,027	55,514	79	0		55,514-	79-
99-01	122,002	204,023	167	0		204,023-	167-
FIVE-YEAR AVERAGE							
97-01	73,201	162,042	221	0		162,042-	221-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1980	2,116,879		0		0		0
1981	1,417,267		0		0		0
1982	2,030,065		0		0		0
1983	5,144,480		0		0		0
1984	966,880		0		0		0
1985	202,755		0		0		0
1986	2,499,565		0		0		0
1987	1,169,925		0		0		0
1988	891,560	338,670	38	80,370	9	258,300-	29-
1989	7,128,907	472,793	7		0	472,793-	7-
1990	5,717,136	78,243	1		0	78,243-	1-
1991	2,025,337	458,901	23	15,683	1	443,218-	22-
1992	2,457,234	315,728	13	16,360	1	299,368-	12-
1993	724,778	56,793	8		0	56,793-	8-
1994	1,561,595	130,565	8	82,789	5	47,776-	3-
1995	227,493	18,273	8	3,412	1	14,861-	7-
1996		660-		172		832	
1997	8,176,947	25,274	0	10,894-	0	36,168-	0
1998	1,180,280	12,676	1		0	12,676-	1-
1999	649,178	715,280	110	12,617	2	702,663-	108-
2000	3,405,873	778,895	23	2,245	0	776,650-	23-
2001	6,813,284	1,734,040	25	19,026	0	1,715,014-	25-
TOTAL	56,507,418	5,135,471	9	221,780	0	4,913,691-	9-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
80-82	1,854,737		0		0		0
81-83	2,863,937		0		0		0
82-84	2,713,808		0		0		0
83-85	2,104,705		0		0		0
84-86	1,223,067		0		0		0
85-87	1,290,748		0		0		0
86-88	1,520,350	112,890	7	26,790	2	86,100-	6-
87-89	3,063,464	270,488	9	26,790	1	243,698-	8-
88-90	4,579,201	296,569	6	26,790	1	269,779-	6-
89-91	4,957,127	336,646	7	5,228	0	331,418-	7-
90-92	3,399,902	284,291	8	10,681	0	273,610-	8-
91-93	1,735,783	277,141	16	10,681	1	266,460-	15-
92-94	1,581,202	167,695	11	33,050	2	134,645-	9-
93-95	837,955	68,544	8	28,734	3	39,810-	5-
94-96	596,363	49,393	8	28,791	5	20,602-	3-
95-97	2,801,480	14,296	1	2,437-	0	16,733-	1-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	3,119,076	12,430	0	3,574-	0	16,004-	1-
97-99	3,335,468	251,077	8	574	0	250,503-	8-
98-00	1,745,110	502,284	29	4,954	0	497,330-	28-
99-01	3,622,778	1,076,072	30	11,296	0	1,064,776-	29-
FIVE-YEAR AVERAGE							
97-01	4,045,112	653,233	16	4,599	0	648,634-	16-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1980	331,238		0		0		0
1981	26,700		0		0		0
1982							
1983	1,188,424		0		0		0
1984	50,000		0		0		0
1985							
1986	1,114,644		0		0		0
1987	872,096		0		0		0
1988	178,434	51,290	29	55,182	31	3,892	2
1989	946,156	173,105	18	25,798-	3-	198,903-	21-
1990	15,184	1,104	7		0	1,104-	7-
1991	354,423	29,011	8		0	29,011-	8-
1992	386,032	21,419	6	1,103	0	20,316-	5-
1993	394,764	21,160	5	2,793	1	18,367-	5-
1994	326,247	68,809	21	53,356	16	15,453-	5-
1995	401,233	47,530	12		0	47,530-	12-
1996		31,732		196		31,536-	
1997	60,631	3,853	6		0	3,853-	6-
1998							
1999	102,629	57,074	56		0	57,074-	56-
2000	129,463	79,256	61		0	79,256-	61-
2001	5,947,911	507,941	9	1,075	0	506,866-	9-
TOTAL	12,826,209	1,093,284	9	87,907	1	1,005,377-	8-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
80-82	119,313		0		0		0
81-83	405,041		0		0		0
82-84	412,808		0		0		0
83-85	412,808		0		0		0
84-86	388,215		0		0		0
85-87	662,247		0		0		0
86-88	721,725	17,097	2	18,394	3	1,297	0
87-89	665,562	74,798	11	9,795	1	65,003-	10-
88-90	379,925	75,166	20	9,795	3	65,371-	17-
89-91	438,588	67,740	15	8,599-	2-	76,339-	17-
90-92	251,880	17,178	7	368	0	16,810-	7-
91-93	378,406	23,863	6	1,299	0	22,564-	6-
92-94	369,014	37,129	10	19,084	5	18,045-	5-
93-95	374,081	45,833	12	18,716	5	27,117-	7-
94-96	242,493	49,357	20	17,851	7	31,506-	13-
95-97	153,955	27,705	18	65	0	27,640-	18-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	20,210	11,862	59	65	0	11,797-	58-
97-99	54,420	20,309	37		0	20,309-	37-
98-00	77,364	45,443	59		0	45,443-	59-
99-01	2,060,001	214,757	10	358	0	214,399-	10-
FIVE-YEAR AVERAGE							
97-01	1,248,127	129,625	10	215	0	129,410-	10-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1980	816		0		0		0
1981	8,435		0		0		0
1982	710,500		0		0		0
1983	102,672		0		0		0
1984	229,253		0		0		0
1985	143,000		0		0		0
1986	195,459		0		0		0
1987	2,298,450		0		0		0
1988	171,078	18,663	11	1,507	1	17,156-	10-
1989	67,475	8,298	12		0	8,298-	12-
1990	500,127	14,901	3		0	14,901-	3-
1991	84,952	4,388	5		0	4,388-	5-
1992	918,509	32,877	4		0	32,877-	4-
1993	107,279	6,312	6		0	6,312-	6-
1994	94,542	6,129	6	14,259	15	8,130	9
1995	402,374	108,041	27	45,628	11	62,413-	16-
1996		806		2,404		1,598	
1997	194,602	93	0		0	93-	0
1998	476,467		0		0		0
1999	72,122	5,795	8		0	5,795-	8-
2000		286,711		94-		286,805-	
2001	192,305	312,230	162		0	312,230-	162-
TOTAL	6,970,417	805,244	12	63,704	1	741,540-	11-
THREE-YEAR MOVING AVERAGES							
80-82	239,917		0		0		0
81-83	273,869		0		0		0
82-84	347,475		0		0		0
83-85	158,308		0		0		0
84-86	189,237		0		0		0
85-87	878,970		0		0		0
86-88	888,329	6,221	1	502	0	5,719-	1-
87-89	845,668	8,987	1	502	0	8,485-	1-
88-90	246,227	13,954	6	502	0	13,452-	5-
89-91	217,518	9,196	4		0	9,196-	4-
90-92	501,196	17,389	3		0	17,389-	3-
91-93	370,247	14,526	4		0	14,526-	4-
92-94	373,443	15,106	4	4,753	1	10,353-	3-
93-95	201,398	40,161	20	19,962	10	20,199-	10-
94-96	165,639	38,325	23	20,764	13	17,561-	11-
95-97	198,992	36,313	18	16,011	8	20,302-	10-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	223,690	300	0	801	0	501	0
97-99	247,730	1,963	1		0	1,963-	1-
98-00	182,863	97,502	53	31-	0	97,533-	53-
99-01	88,142	201,579	229	31-	0	201,610-	229-
FIVE-YEAR AVERAGE							
97-01	187,099	120,966	65	19-	0	120,985-	65-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1980	59,719		0		0		0
1981	387,518		0		0		0
1982	288,480-		0		0		0
1983	65,378		0		0		0
1984	137,887		0		0		0
1985	81,549		0		0		0
1986	81,664		0		0		0
1987	498,061		0		0		0
1988	2,434,238	50,597	2	57,156	2	6,559	0
1989	2,147,033-	31,164	1-	11,739-	1	42,903-	2
1990	259,871	50,256	19	14,019	5	36,237-	14-
1991	314,266	36,620	12	28,686	9	7,934-	3-
1992	51,329	39,208	76	1,269	2	37,939-	74-
1993	31,128	697	2	97,002	312	96,305	309
1994	810,788	45,361	6	20,512	3	24,849-	3-
1995		133		20,199		20,066	
1996				1,021		1,021	
1997	2,691		0	277	10	277	10
1998	45,988		0		0		0
1999							
2000	190,058	338,494	178	49-	0	338,543-	178-
2001	447,670	64,540	14	3,581	1	60,959-	14-
TOTAL	3,464,290	657,070	19	231,934	7	425,136-	12-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
80-82	52,919		0		0		0
81-83	54,805		0		0		0
82-84	28,405-		0		0		0
83-85	94,938		0		0		0
84-86	100,367		0		0		0
85-87	220,425		0		0		0
86-88	1,004,654	16,866	2	19,052	2	2,186	0
87-89	261,755	27,254	10	15,139	6	12,115-	5-
88-90	182,359	44,006	24	19,812	11	24,194-	13-
89-91	524,299-	39,347	8-	10,322	2-	29,025-	6
90-92	208,489	42,028	20	14,658	7	27,370-	13-
91-93	132,241	25,508	19	42,319	32	16,811	13
92-94	297,748	28,422	10	39,594	13	11,172	4
93-95	280,639	15,397	5	45,904	16	30,507	11
94-96	270,263	15,165	6	13,911	5	1,254-	0
95-97	897	44	5	7,166	799	7,122	794

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	16,226		0	433	3	433	3
97-99	16,226		0	92	1	92	1
98-00	78,682	112,831	143	16-	0	112,847-	143-
99-01	212,576	134,345	63	1,177	1	133,168-	63-
FIVE-YEAR AVERAGE							
97-01	137,281	80,607	59	762	1	79,845-	58-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 321 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1988	211,951		0		0		0
1989	38,814	234	1		0	234-	1-
1990	413,702	11,111	3		0	11,111-	3-
1991	398,361	406-	0		0	406	0
1992	616,424	2,787	0	33,431	5	30,644	5
1993	898,813	12,334	1	216,914	24	204,580	23
1994	444,774	23,082	5		0	23,082-	5-
1995	181,856	7,089	4	1,002	1	6,087-	3-
1996		10,680				10,680-	
1997	220,375	5,918	3	3,932	2	1,986-	1-
1998	4,879,659	210,023	4	52,158	1	157,865-	3-
1999	3,558,837	29,507	1	2,787-	0	32,294-	1-
2000	460,395	4,053	1	776	0	3,277-	1-
2001	374,905	1,260	0	1,163	0	97-	0
TOTAL	12,698,866	317,672	3	306,589	2	11,083-	0
THREE-YEAR MOVING AVERAGES							
88-90	221,489	3,782	2		0	3,782-	2-
89-91	283,626	3,646	1		0	3,646-	1-
90-92	476,162	4,497	1	11,144	2	6,647	1
91-93	637,866	4,905	1	83,448	13	78,543	12
92-94	653,337	12,734	2	83,448	13	70,714	11
93-95	508,481	14,168	3	72,639	14	58,471	11
94-96	208,877	13,617	7	334	0	13,283-	6-
95-97	134,077	7,896	6	1,645	1	6,251-	5-
96-98	1,700,011	75,540	4	18,696	1	56,844-	3-
97-99	2,886,290	81,816	3	17,767	1	64,049-	2-
98-00	2,966,297	81,194	3	16,716	1	64,478-	2-
99-01	1,464,712	11,607	1	282-	0	11,889-	1-
FIVE-YEAR AVERAGE							
97-01	1,898,834	50,152	3	11,048	1	39,104-	2-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 322 REACTOR PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1988	7,008,336	16,542	0		0	16,542-	0
1989	552,119	55,825	10	45,963	8	9,862-	2-
1990	11,157,106	29,637-	0	1,446,704	13	1,476,341	13
1991	1,150,690	519,884	45	465,373-	40-	985,257-	86-
1992	6,404,964	185,454	3	445,132-	7-	630,586-	10-
1993	3,619,994	49,675	1	873,626	24	823,951	23
1994	2,602,348	131,323	5		0	131,323-	5-
1995	3,252,869	98,852	3	17,921	1	80,931-	2-
1996		191,035				191,035-	
1997	1,887,625	8,412	0	6,614	0	1,798-	0
1998	9,895,213	87,387	1	678	0	86,709-	1-
1999	1,141,831	338,732	30		0	338,732-	30-
2000	932,468	44,184	5		0	44,184-	5-
2001	5,347,000	974,159	18	4,803	0	969,356-	18-
TOTAL	54,952,563	2,671,827	5	1,485,804	3	1,186,023-	2-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
88-90	6,239,187	14,243	0	497,556	8	483,313	8
89-91	4,286,638	182,024	4	342,431	8	160,407	4
90-92	6,237,587	225,234	4	178,733	3	46,501-	1-
91-93	3,725,216	251,671	7	12,293-	0	263,964-	7-
92-94	4,209,102	122,151	3	142,831	3	20,680	0
93-95	3,158,404	93,283	3	297,182	9	203,899	6
94-96	1,951,739	140,403	7	5,974	0	134,429-	7-
95-97	1,713,498	99,433	6	8,178	0	91,255-	5-
96-98	3,927,613	95,611	2	2,431	0	93,180-	2-
97-99	4,308,223	144,843	3	2,431	0	142,412-	3-
98-00	3,989,837	156,767	4	226	0	156,541-	4-
99-01	2,473,767	452,358	18	1,601	0	450,757-	18-

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
97-01	3,840,828	290,575	8	2,419	0	288,156-	8-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 323 TURBOGENERATOR UNITS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1988	327,181		0		0		0
1989	438,936	2,414	1		0	2,414-	1-
1990	129,422	48	0		0	48-	0
1991	508,241	91,924	18		0	91,924-	18-
1992	2,297,778	69,687	3		0	69,687-	3-
1993	279,378	3,834	1	67,423	24	63,589	23
1994	1,677,331	84,644	5		0	84,644-	5-
1995	962,037	29,236	3	5,300	1	23,936-	2-
1996		56,499				56,499-	
1997	718,199	815	0		0	815-	0
1998	4,254,130	28,486	1		0	28,486-	1-
1999	63,292	16,398	26		0	16,398-	26-
2000	658,116	2,339-	0		0	2,339	0
2001	1,620,213	438,718	27		0	438,718-	27-
TOTAL	13,934,254	820,364	6	72,723	1	747,641-	5-

THREE-YEAR MOVING AVERAGES

88-90	298,513	821	0		0	821-	0
89-91	358,866	31,462	9		0	31,462-	9-
90-92	978,480	53,886	6		0	53,886-	6-
91-93	1,028,466	55,148	5	22,474	2	32,674-	3-
92-94	1,418,162	52,721	4	22,474	2	30,247-	2-
93-95	972,915	39,238	4	24,241	2	14,997-	2-
94-96	879,789	56,793	6	1,767	0	55,026-	6-
95-97	560,079	28,850	5	1,767	0	27,083-	5-
96-98	1,657,443	28,600	2		0	28,600-	2-
97-99	1,678,540	15,233	1		0	15,233-	1-
98-00	1,658,513	14,181	1		0	14,181-	1-
99-01	780,540	150,925	19		0	150,925-	19-

FIVE-YEAR AVERAGE

97-01	1,462,790	96,415	7		0	96,415-	7-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 324 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1988	73,028		0		0		0
1989	414,957	2,441	1	1,815	0	626-	0
1990	654,806	3,448	1		0	3,448-	1-
1991	27,139	787-	3-		0	787	3
1992	620,339	52,465	8		0	52,465-	8-
1993	68,521	940	1	16,536	24	15,596	23
1994	130,769	6,599	5		0	6,599-	5-
1995	3,238	98	3	18	1	80-	2-
1996		190				190-	
1997							
1998	891,291	28,589	3	5,865	1	22,724-	3-
1999	2,110	587	28		0	587-	28-
2000	54,691	13,803	25		0	13,803-	25-
2001	296,956	70,074	24		0	70,074-	24-
TOTAL	3,237,845	178,447	6	24,234	1	154,213-	5-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
88-90	380,930	1,963	1	605	0	1,358-	0
89-91	365,634	1,701	0	605	0	1,096-	0
90-92	434,095	18,375	4		0	18,375-	4-
91-93	238,666	17,539	7	5,512	2	12,027-	5-
92-94	273,210	20,001	7	5,512	2	14,489-	5-
93-95	67,509	2,546	4	5,518	8	2,972	4
94-96	44,669	2,296	5	6	0	2,290-	5-
95-97	1,079	96	9	6	1	90-	8-
96-98	297,097	9,593	3	1,955	1	7,638-	3-
97-99	297,800	9,725	3	1,955	1	7,770-	3-
98-00	316,031	14,326	5	1,955	1	12,371-	4-
99-01	117,919	28,154	24		0	28,154-	24-

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
97-01	249,010	22,610	9	1,173	0	21,437-	9-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 325 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1988	61,364	2,809	5	81,562	133	78,753	128
1989							
1990	159,497	3,810	2		0	3,810-	2-
1991	251,814	135	0	135	0		0
1992	151,742	9,755	6	37,726	25	27,971	18
1993	5,579,661	76,567	1	1,346,560	24	1,269,993	23
1994	5,874,215	296,632	5		0	296,632-	5-
1995							
1996							
1997	3,131		0	72	2	72	2
1998	1,498,420	66,483	4	16,612	1	49,871-	3-
1999	3,406,347	7,871	0	2,712-	0	10,583-	0
2000	16,527,538	177,530	1	25,580	0	151,950-	1-
2001	4,685,473	495,818	11	9,298	0	486,520-	10-
TOTAL	38,199,202	1,137,410	3	1,514,833	4	377,423	1
THREE-YEAR MOVING AVERAGES							
88-90	73,620	2,206	3	27,187	37	24,981	34
89-91	137,104	1,315	1	45	0	1,270-	1-
90-92	187,684	4,567	2	12,620	7	8,053	4
91-93	1,994,406	28,819	1	461,474	23	432,655	22
92-94	3,868,539	127,651	3	461,429	12	333,778	9
93-95	3,817,959	124,400	3	448,853	12	324,453	8
94-96	1,958,072	98,877	5		0	98,877-	5-
95-97	1,044		0	24	2	24	2
96-98	500,517	22,161	4	5,561	1	16,600-	3-
97-99	1,635,966	24,785	2	4,657	0	20,128-	1-
98-00	7,144,101	83,961	1	13,160	0	70,801-	1-
99-01	8,206,453	227,073	3	10,722	0	216,351-	3-
FIVE-YEAR AVERAGE							
97-01	5,224,182	149,540	3	9,770	0	139,770-	3-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1983	900		0		0		0
1984							
1985							
1986							
1987	38,826		0		0		0
1988							
1989							
1990							
1991							
1992		13,000				13,000-	
1993							
1994	14,269	538-	4-		0	538	4
1995	3		0	9	300	9	300
1996		2				2-	
1997		1				1-	
1998							
1999							
2000	23,200		0		0		0
2001							
TOTAL	77,198	12,465	16	9	0	12,456-	16-

THREE-YEAR MOVING AVERAGES

83-85	300		0		0		0
84-86							
85-87	12,942		0		0		0
86-88	12,942		0		0		0
87-89	12,942		0		0		0
88-90							
89-91							
90-92		4,333				4,333-	
91-93		4,333				4,333-	
92-94	4,756	4,154	87		0	4,154-	87-
93-95	4,757	179-	4-	3	0	182	4
94-96	4,757	179-	4-	3	0	182	4
95-97	1	1	100	3	300	2	200
96-98		1				1-	
97-99							
98-00	7,733		0		0		0
99-01	7,733		0		0		0

FIVE-YEAR AVERAGE

97-01	4,640		0		0		0

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 342 FUEL HOLDERS, PRODUCTS AND ACCESSORIES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1983	3,000		0		0		0
1984							
1985							
1986	10,580		0		0		0
1987							
1988							
1989							
1990	26,220	254	1		0	254-	1-
1991	230,973	11,655	5	4,322	2	7,333-	3-
1992	41,437		0		0		0
1993	184,925	24,835	13	26,887	15	2,052	1
1994	65,794	3,471	5		0	3,471-	5-
1995							
1996							
1997							
1998							
1999							
2000							
2001							
TOTAL	562,929	40,215	7	31,209	6	9,006-	2-

THREE-YEAR MOVING AVERAGES

83-85	1,000		0		0		0
84-86	3,527		0		0		0
85-87	3,527		0		0		0
86-88	3,527		0		0		0
87-89							
88-90	8,740	85	1		0	85-	1-
89-91	85,731	3,970	5	1,441	2	2,529-	3-
90-92	99,543	3,970	4	1,441	1	2,529-	3-
91-93	152,445	12,163	8	10,403	7	1,760-	1-
92-94	97,385	9,435	10	8,962	9	473-	0
93-95	83,573	9,435	11	8,962	11	473-	1-
94-96	21,931	1,157	5		0	1,157-	5-
95-97							
96-98							
97-99							
98-00							
99-01							

FIVE-YEAR AVERAGE

97-01

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 343 PRIME MOVERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1982	324,806		0		0		0
1983							
1984							
1985							
1986							
1987							
1988							
1989							
1990							
1991							
1992	800,930	36,508	5		0	36,508-	5-
1993							
1994							
1995							
1996							
1997							
1998							
1999	96,461	16,221	17		0	16,221-	17-
2000							
2001	367,510	112,670	31		0	112,670-	31-
TOTAL	1,589,707	165,399	10		0	165,399-	10-
THREE-YEAR MOVING AVERAGES							
82-84	108,269		0		0		0
83-85							
84-86							
85-87							
86-88							
87-89							
88-90							
89-91							
90-92	266,977	12,169	5		0	12,169-	5-
91-93	266,977	12,169	5		0	12,169-	5-
92-94	266,977	12,169	5		0	12,169-	5-
93-95							
94-96							
95-97							
96-98							
97-99	32,154	5,407	17		0	5,407-	17-
98-00	32,154	5,407	17		0	5,407-	17-
99-01	154,657	42,963	28		0	42,963-	28-
FIVE-YEAR AVERAGE							
97-01	92,794	25,778	28		0	25,778-	28-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 344 GENERATORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1980	5,089		0		0		0
1981	235,355		0		0		0
1982							
1983	133,000		0		0		0
1984							
1985							
1986	192,621		0		0		0
1987	66,889		0		0		0
1988	296,240		0		0		0
1989	238,050		0		0		0
1990							
1991		16,671				16,671-	
1992	158,334	23,762	15		0	23,762-	15-
1993	699,859	151,167	22	43,087	6	108,080-	15-
1994	436,512	25,277	6		0	25,277-	6-
1995	224,378	10,335	5	657,203	293	646,868	288
1996		123,081				123,081-	
1997		71,642				71,642-	
1998		1,159				1,159-	
1999							
2000	1,330,919	3,150	0		0	3,150-	0
2001	295,240	101,957	35		0	101,957-	35-
TOTAL	4,312,486	528,201	12	700,290	16	172,089	4

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
80-82	80,148		0		0		0
81-83	122,785		0		0		0
82-84	44,333		0		0		0
83-85	44,333		0		0		0
84-86	64,207		0		0		0
85-87	86,503		0		0		0
86-88	185,250		0		0		0
87-89	200,393		0		0		0
88-90	178,097		0		0		0
89-91	79,350	5,557	7		0	5,557-	7-
90-92	52,778	13,478	26		0	13,478-	26-
91-93	286,064	63,867	22	14,362	5	49,505-	17-
92-94	431,568	66,735	15	14,362	3	52,373-	12-
93-95	453,583	62,259	14	233,430	51	171,171	38
94-96	220,297	52,898	24	219,068	99	166,170	75
95-97	74,793	68,352	91	219,068	293	150,716	202

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 344 GENERATORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98		65,294				65,294-	
97-99		24,267				24,267-	
98-00	443,640	1,436	0		0	1,436-	0
99-01	542,053	35,036	6		0	35,036-	6-
FIVE-YEAR AVERAGE							
97-01	325,232	35,582	11		0	35,582-	11-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1980	2,500		0		0		0
1981							
1982							
1983							
1984	120,000		0		0		0
1985	15,453		0		0		0
1986							
1987	14,517		0		0		0
1988							
1989							
1990	81,995	516	1		0	516-	1-
1991	14,468	26,640	184		0	26,640-	184-
1992							
1993	29,497	1,279	4		0	1,279-	4-
1994	225,535	1,454-	1-		0	1,454	1
1995							
1996							
1997							
1998							
1999							
2000	53,090	16,000	30		0	16,000-	30-
2001		414,000				414,000-	
TOTAL	557,055	456,981	82		0	456,981-	82-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
80-82	833		0		0		0
81-83							
82-84	40,000		0		0		0
83-85	45,151		0		0		0
84-86	45,151		0		0		0
85-87	9,990		0		0		0
86-88	4,839		0		0		0
87-89	4,839		0		0		0
88-90	27,332	172	1		0	172-	1-
89-91	32,154	9,052	28		0	9,052-	28-
90-92	32,154	9,052	28		0	9,052-	28-
91-93	14,655	9,306	64		0	9,306-	64-
92-94	85,011	58-	0		0	58	0
93-95	85,011	58-	0		0	58	0
94-96	75,178	485-	1-		0	485	1
95-97							

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98							
97-99							
98-00	17,697	5,333	30	0		5,333-	30-
99-01	17,697	143,333	810	0		143,333-	810-
FIVE-YEAR AVERAGE							
97-01	10,618	86,000	810	0		86,000-	810-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1985	3,000		0		0		0
1986							
1987	161,389		0		0		0
1988							
1989							
1990							
1991							
1992	7,301	1,290	18		0	1,290-	18-
1993							
1994							
1995							
1996							
1997							
1998							
1999							
2000	25,000	12,914	52		0	12,914-	52-
2001	14,994	5,178	35		0	5,178-	35-
TOTAL	211,684	19,382	9		0	19,382-	9-
THREE-YEAR MOVING AVERAGES							
85-87	54,796		0		0		0
86-88	53,796		0		0		0
87-89	53,796		0		0		0
88-90							
89-91							
90-92	2,434	430	18		0	430-	18-
91-93	2,434	430	18		0	430-	18-
92-94	2,434	430	18		0	430-	18-
93-95							
94-96							
95-97							
96-98							
97-99							
98-00	8,333	4,305	52		0	4,305-	52-
99-01	13,331	6,031	45		0	6,031-	45-
FIVE-YEAR AVERAGE							
97-01	7,999	3,618	45		0	3,618-	45-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 352 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1981	7,769		0		0		0
1982							
1983							
1984	23,172		0		0		0
1985							
1986	9,555		0		0		0
1987	11,879		0		0		0
1988	103		0	3	3	3	3
1989	23,438	2,579	11	5,475	23	2,896	12
1990	23,438-	574-	2	105-	0	469	2-
1991	36,862	10,399	28	2,698	7	7,701-	21-
1992	9,127	2,276	25	209	2	2,067-	23-
1993	54,554		0		0		0
1994	54,180		0		0		0
1995	33,473		0		0		0
1996							
1997							
1998							
1999	10,062		0		0		0
2000	40,153		0		0		0
2001							
TOTAL	290,889	14,680	5	8,280	3	6,400-	2-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
81-83	2,590		0		0		0
82-84	7,724		0		0		0
83-85	7,724		0		0		0
84-86	10,909		0		0		0
85-87	7,145		0		0		0
86-88	7,179		0	1	0	1	0
87-89	11,807	860	7	1,826	15	966	8
88-90	34	668		1,791		1,123	
89-91	12,287	4,135	34	2,689	22	1,446-	12-
90-92	7,517	4,034	54	934	12	3,100-	41-
91-93	33,514	4,225	13	969	3	3,256-	10-
92-94	39,287	759	2	70	0	689-	2-
93-95	47,402		0		0		0
94-96	29,218		0		0		0
95-97	11,158		0		0		0
96-98							
97-99	3,354		0		0		0

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 352 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
98-00	16,738		0		0		0
99-01	16,738		0		0		0
FIVE-YEAR AVERAGE							
97-01	10,043		0		0		0

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 353 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1980	125,483		0		0		0
1981	275,556		0		0		0
1982	407,743		0		0		0
1983	469,645		0		0		0
1984	204,881		0		0		0
1985	319,608		0		0		0
1986	784,405		0		0		0
1987	816,410		0		0		0
1988	2,026,183	58,698	3	1,369,474	68	1,310,776	65
1989	1,422,638	86,903	6	251,449	18	164,546	12
1990	1,843,274	75,443	4	432,307	23	356,864	19
1991	952,849	157,585	17	472,908	50	315,323	33
1992	2,591,893	132,551	5	257,624	10	125,073	5
1993	2,249,789	197,931	9	47,326	2	150,605-	7-
1994	1,080,778	220,445	20	7,144-	1-	227,589-	21-
1995	195,122	39,393	20	56,636	29	17,243	9
1996	9,275	74,642	805	35,165	379	39,477-	426-
1997	240,952	113,233	47	25,064	10	88,169-	37-
1998	330,081	3,180	1	538,635	163	535,455	162
1999	882,449	1,027-	0	1,069,324	121	1,070,351	121
2000	2,786,516	14,265	1	446,373	16	432,108	16
2001	2,369,789	874,679	37	309,923-	13-	1,184,602-	50-
TOTAL	22,385,319	2,047,921	9	4,685,218	21	2,637,297	12

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
80-82	269,594		0		0		0
81-83	384,315		0		0		0
82-84	360,756		0		0		0
83-85	331,378		0		0		0
84-86	436,298		0		0		0
85-87	640,141		0		0		0
86-88	1,208,999	19,566	2	456,491	38	436,925	36
87-89	1,421,744	48,534	3	540,308	38	491,774	35
88-90	1,764,032	73,681	4	684,410	39	610,729	35
89-91	1,406,254	106,644	8	385,555	27	278,911	20
90-92	1,796,005	121,860	7	387,613	22	265,753	15
91-93	1,931,510	162,689	8	259,286	13	96,597	5
92-94	1,974,153	183,642	9	99,269	5	84,373-	4-
93-95	1,175,230	152,590	13	32,273	3	120,317-	10-
94-96	428,392	111,493	26	28,219	7	83,274-	19-
95-97	148,450	75,756	51	38,955	26	36,801-	25-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 353 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	193,436	63,685	33	199,621	103	135,936	70
97-99	484,494	38,462	8	544,341	112	505,879	104
98-00	1,333,015	5,473	0	684,777	51	679,304	51
99-01	2,012,918	295,972	15	401,925	20	105,953	5
FIVE-YEAR AVERAGE							
97-01	1,321,957	200,866	15	353,895	27	153,029	12

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNTS 354, 355 & 356 TOWERS, POLES & OVERHEAD CONDUCTORS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1980	517,619	303,170	59	192,023	37	111,147-	21-
1981	229,929	287,395	125	329,140	143	41,745	18
1982	331,261	378,015	114	323,922	98	54,093-	16-
1983	1,001,241	338,682	34	286,023	29	52,659-	5-
1984	206,395-	347,556	168-	179,758	87-	167,798-	81
1985	644,517	538,352	84	128,457	20	409,895-	64-
1986	585,840	616,790	105	268,556	46	348,234-	59-
1987	2,148,690	489,896	23	269,361	13	220,535-	10-
1988	772,941	630,127	82	593,102	77	37,025-	5-
1989	671,628	1,504,302	224	1,374,554	205	129,748-	19-
1990	2,409,924	159,810	7	864,595	36	704,785	29
1991	1,718,190	352,997	21	2,619,081	152	2,266,084	132
1992	510,971	298,217	58	151,582	30	146,635-	29-
1993	1,348,534	628,431	47	935,390	69	306,959	23
1994	980,102	558,714	57	148,931	15	409,783-	42-
1995	1,082,150	644,686	60	652,815	60	8,129	1
1996		528,267		87,549		440,718-	
1997	671,273	125,482	19	311,461	46	185,979	28
1998	613,629	27,871	5	283,603	46	255,732	42
1999	759,356	25,074	3	190,406	25	165,332	22
2000	512,480	950,115	185	1,769,470	345	819,355	160
2001	2,833,169	2,090,623	74	1,730,051	61	360,572-	13-
TOTAL	20,137,049	11,824,572	59	13,689,830	68	1,865,258	9

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
80-82	359,603	322,860	90	281,695	78	41,165-	11-
81-83	520,810	334,697	64	313,028	60	21,669-	4-
82-84	375,369	354,751	95	263,234	70	91,517-	24-
83-85	479,788	408,197	85	198,079	41	210,118-	44-
84-86	341,321	500,899	147	192,257	56	308,642-	90-
85-87	1,126,349	548,346	49	222,125	20	326,221-	29-
86-88	1,169,157	578,938	50	377,006	32	201,932-	17-
87-89	1,197,753	874,775	73	745,672	62	129,103-	11-
88-90	1,284,831	764,746	60	944,084	73	179,338	14
89-91	1,599,914	672,370	42	1,619,410	101	947,040	59
90-92	1,546,362	270,341	17	1,211,753	78	941,412	61
91-93	1,192,565	426,548	36	1,235,351	104	808,803	68
92-94	946,536	495,121	52	411,968	44	83,153-	9-
93-95	1,136,929	610,610	54	579,045	51	31,565-	3-
94-96	687,417	577,222	84	296,432	43	280,790-	41-
95-97	584,474	432,812	74	350,609	60	82,203-	14-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNTS 354, 355 & 356 TOWERS, POLES & OVERHEAD CONDUCTORS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
96-98	428,301	227,207	53	227,538	53	331	0
97-99	681,419	59,476	9	261,824	38	202,348	30
98-00	628,488	334,353	53	747,827	119	413,474	66
99-01	1,368,335	1,021,937	75	1,229,976	90	208,039	15
FIVE-YEAR AVERAGE							
97-01	1,077,982	643,833	60	856,998	80	213,165	20

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNTS 357 & 358 UNDERGROUND CONDUIT AND CONDUCTORS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1980	103,646		0		0		0
1981							
1982							
1983							
1984	120		0		0		0
1985		30				30-	
1986		3,709				3,709-	
1987							
1988		5,748		2,025		3,723-	
1989				2,852		2,852	
1990				8,897		8,897	
1991	24,086		0	32,445	135	32,445	135
1992							
1993	190,378	1,060	1		0	1,060-	1-
1994							
1995		8,730		1,499,700		1,490,970	
1996		1,551				1,551-	
1997	523,379	3,146	1	17,465	3	14,319	3
1998	523,475		0		0		0
1999	707,749		0		0		0
2000		744				744-	
2001	2,939	32,056		89,381		57,325	
TOTAL	2,075,772	56,774	3	1,652,765	80	1,595,991	77

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
80-82	34,549		0		0		0
81-83							
82-84	40		0		0		0
83-85	40	10	25		0	10-	25-
84-86	40	1,246			0	1,246-	
85-87		1,246				1,246-	
86-88		3,152		675		2,477-	
87-89		1,916		1,626		290-	
88-90		1,916		4,591		2,675	
89-91	8,029		0	14,731	183	14,731	183
90-92	8,029		0	13,781	172	13,781	172
91-93	71,488	353	0	10,815	15	10,462	15
92-94	63,459	353	1		0	353-	1-
93-95	63,459	3,263	5	499,900	788	496,637	783
94-96		3,427		499,900		496,473	
95-97	174,460	4,476	3	505,722	290	501,246	287

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNTS 357 & 358 UNDERGROUND CONDUIT AND CONDUCTORS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
96-98	348,951	1,566	0	5,822	2	4,256	1
97-99	584,868	1,049	0	5,822	1	4,773	1
98-00	410,408	248	0		0	248-	0
99-01	236,896	10,933	5	29,794	13	18,861	8
FIVE-YEAR AVERAGE							
97-01	351,508	7,189	2	21,369	6	14,180	4

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1980	2,645		0		0		0
1981	1,652		0		0		0
1982	28,083		0		0		0
1983	70,922		0		0		0
1984	12,987		0		0		0
1985	11,587		0		0		0
1986	23,920		0		0		0
1987	16,814		0		0		0
1988	55,932	9,566	17	20,586	37	11,020	20
1989	85,700	14,090	16	20,270-	24-	34,360-	40-
1990	82,322	11,190	14	10,110	12	1,080-	1-
1991	28,917	8,544	30	848	3	7,696-	27-
1992	33,563	14,048	42	6,058	18	7,990-	24-
1993	2,304		0		0		0
1994	12,259		0		0		0
1995	11,480		0		0		0
1996							
1997							
1998							
1999	39,557		0		0		0
2000	3,420		0		0		0
2001	46,469		0		0		0
TOTAL	570,533	57,438	10	17,332	3	40,106-	7-

THREE-YEAR MOVING AVERAGES

80-82	10,793		0		0		0
81-83	33,552		0		0		0
82-84	37,331		0		0		0
83-85	31,832		0		0		0
84-86	16,165		0		0		0
85-87	17,440		0		0		0
86-88	32,222	3,189	10	6,862	21	3,673	11
87-89	52,815	7,885	15	105	0	7,780-	15-
88-90	74,651	11,615	16	3,475	5	8,140-	11-
89-91	65,646	11,275	17	3,104-	5-	14,379-	22-
90-92	48,267	11,261	23	5,672	12	5,589-	12-
91-93	21,595	7,531	35	2,302	11	5,229-	24-
92-94	16,042	4,683	29	2,019	13	2,664-	17-
93-95	8,681		0		0		0
94-96	7,913		0		0		0
95-97	3,827		0		0		0

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98							
97-99	13,186		0		0		0
98-00	14,326		0		0		0
99-01	29,815		0		0		0
FIVE-YEAR AVERAGE							
97-01	17,889		0		0		0

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 362 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1980	353,034	44,600	13	23,940	7	20,660-	6-
1981	325,601	114,846	35	14,271	4	100,575-	31-
1982	667,561	158,044	24	101,079	15	56,965-	9-
1983	1,207,460	119,423	10	145,734	12	26,311	2
1984	787,759	144,531	18	131,469	17	13,062-	2-
1985	1,050,951	106,927	10	146,551	14	39,624	4
1986	619,146	60,520	10	16,662	3	43,858-	7-
1987	864,761	160,911	19	36,980	4	123,931-	14-
1988	3,816,364	246,124	6	2,309,201	61	2,063,077	54
1989	1,649,315	206,957	13	269,663	16	62,706	4
1990	1,092,237	131,454	12	445,162	41	313,708	29
1991	1,175,687	157,459	13	553,850	47	396,391	34
1992	834,931	215,787	26	239,226	29	23,439	3
1993	1,679,689	141,103	8	24,493	1	116,610-	7-
1994	644,300	54,683	8	197,815	31	143,132	22
1995	63,199	53,256	84	52,682	83	574-	1-
1996		120,490		685,379		564,889	
1997		65,297		740,781		675,484	
1998	918,692	7,693	1	2,467,092	269	2,459,399	268
1999	5,015,699	254,692	5	318,558	6	63,866	1
2000	723,460	257,728	36	1,439,168	199	1,181,440	163
2001	1,100,833	788,295	72	2,450,986	223	1,662,691	151
TOTAL	24,590,679	3,610,820	15	12,810,742	52	9,199,922	37

THREE-YEAR MOVING AVERAGES

80-82	448,732	105,830	24	46,430	10	59,400-	13-
81-83	733,541	130,771	18	87,028	12	43,743-	6-
82-84	887,593	140,666	16	126,094	14	14,572-	2-
83-85	1,015,390	123,627	12	141,251	14	17,624	2
84-86	819,285	103,993	13	98,227	12	5,766-	1-
85-87	844,953	109,453	13	66,731	8	42,722-	5-
86-88	1,766,757	155,852	9	787,614	45	631,762	36
87-89	2,110,147	204,664	10	871,948	41	667,284	32
88-90	2,185,972	194,845	9	1,008,009	46	813,164	37
89-91	1,305,746	165,290	13	422,892	32	257,602	20
90-92	1,034,285	168,233	16	412,746	40	244,513	24
91-93	1,230,102	171,450	14	272,523	22	101,073	8
92-94	1,052,973	137,191	13	153,845	15	16,654	2
93-95	795,729	83,014	10	91,664	12	8,650	1
94-96	235,833	76,143	32	311,959	132	235,816	100
95-97	21,066	79,681	378	492,947		413,266	

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 362 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	306,231	64,493	21	1,297,750	424	1,233,257	403
97-99	1,978,130	109,227	6	1,175,477	59	1,066,250	54
98-00	2,219,283	173,371	8	1,408,272	63	1,234,901	56
99-01	2,279,997	433,572	19	1,402,904	62	969,332	43
FIVE-YEAR AVERAGE							
97-01	1,551,737	274,741	18	1,483,317	96	1,208,576	78

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNTS 364 & 365 POLES, TOWERS AND OVERHEAD CONDUCTORS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1980	1,735,193	676,096	39	1,473,332	85	797,236	46
1981	1,566,111	907,483	58	2,010,926	128	1,103,443	70
1982	1,974,404	1,028,437	52	1,583,540	80	555,103	28
1983	1,813,310	995,052	55	1,354,932	75	359,880	20
1984	2,202,512	1,029,406	47	1,925,720	87	896,314	41
1985	2,281,037	1,137,457	50	247,955	11	889,502-	39-
1986	2,695,275	1,908,860	71	1,690,172	63	218,688-	8-
1987	4,966,558	1,629,089	33	3,131,709	63	1,502,620	30
1988	5,426,903	1,766,362	33	3,361,392	62	1,595,030	29
1989	3,268,983	1,089,810	33	2,716,388	83	1,626,578	50
1990	3,691,097	1,008,315	27	3,161,527	86	2,153,212	58
1991	3,308,975	945,341	29	1,153,774	35	208,433	6
1992	4,268,305	1,973,019	46	2,018,618	47	45,599	1
1993	4,143,841	2,117,296	51	1,080,642	26	1,036,654-	25-
1994	3,156,765	2,288,803	73	2,060,563	65	228,240-	7-
1995	3,993,302	1,270,205	32	1,860,460	47	590,255	15
1996	2,035,693	1,131,342	56	1,288,338	63	156,996	8
1997	4,849,288	850,562	18	1,043,073	22	192,511	4
1998	12,281,069	203,001	2	2,026,534	17	1,823,533	15
1999	5,163,278	110,386	2	1,937,037	38	1,826,651	35
2000	8,293,942	922,537	11	3,564,474	43	2,641,937	32
2001	7,178,677	2,831,814	39	1,133,200	16	1,698,614-	24-
TOTAL	90,294,518	27,820,673	31	41,824,306	46	14,003,633	16

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
80-82	1,758,569	870,672	50	1,689,266	96	818,594	47
81-83	1,784,608	976,991	55	1,649,799	92	672,808	38
82-84	1,996,742	1,017,632	51	1,621,397	81	603,765	30
83-85	2,098,953	1,053,972	50	1,176,202	56	122,230	6
84-86	2,392,941	1,358,574	57	1,287,949	54	70,625-	3-
85-87	3,314,290	1,558,469	47	1,689,945	51	131,476	4
86-88	4,362,912	1,768,104	41	2,727,758	63	959,654	22
87-89	4,554,148	1,495,087	33	3,069,830	67	1,574,743	35
88-90	4,128,994	1,288,162	31	3,079,769	75	1,791,607	43
89-91	3,423,018	1,014,489	30	2,343,896	68	1,329,407	39
90-92	3,756,126	1,308,892	35	2,111,306	56	802,414	21
91-93	3,907,040	1,678,552	43	1,417,678	36	260,874-	7-
92-94	3,856,304	2,126,373	55	1,719,941	45	406,432-	11-
93-95	3,764,636	1,892,102	50	1,667,221	44	224,881-	6-
94-96	3,061,920	1,563,450	51	1,736,454	57	173,004	6
95-97	3,626,094	1,084,036	30	1,397,290	39	313,254	9

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNTS 364 & 365 POLES, TOWERS AND OVERHEAD CONDUCTORS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
96-98	6,388,683	728,302	11	1,452,648	23	724,346	11
97-99	7,431,212	387,983	5	1,668,881	22	1,280,898	17
98-00	8,579,430	411,975	5	2,509,348	29	2,097,373	24
99-01	6,878,632	1,288,246	19	2,211,570	32	923,324	13
FIVE-YEAR AVERAGE							
97-01	7,553,251	983,660	13	1,940,863	26	957,203	13

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNTS 366 & 367 UNDERGROUND CONDUIT AND CONDUCTORS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1980	295,255	131,107	44	52,799	18	78,308-	27-
1981	355,642	206,243	58	154,349	43	51,894-	15-
1982	333,199	226,710	68	268,215	80	41,505	12
1983	245,403	212,106	86	63,495	26	148,611-	61-
1984	706,678	295,565	42	148,923	21	146,642-	21-
1985	669,681	365,426	55	58,873	9	306,553-	46-
1986	868,521	474,919	55	189,629	22	285,290-	33-
1987	1,803,973	432,143	24	127,669	7	304,474-	17-
1988	1,474,291	284,197	19	340,565	23	56,368	4
1989	1,916,091	168,564	9	259,046	14	90,482	5
1990	2,214,122	153,749	7	845,313	38	691,564	31
1991	6,672,075	480,402	7	481,990	7	1,588	0
1992	7,772,523	1,182,414	15	181,544	2	1,000,870-	13-
1993	13,884,753	1,303,100	9	770,847	6	532,253-	4-
1994	6,528,552	589,850	9	716,672	11	126,822	2
1995	6,064,685	883,089	15	227,138	4	655,951-	11-
1996	2,735,160	563,139	21	298,746	11	264,393-	10-
1997	9,608,328	456,194	5	196,108	2	260,086-	3-
1998	23,237,000	63,109-	0	321,114	1	384,223	2
1999	10,485,692	207,347	2	272,681	3	65,334	1
2000	11,925,094	715,610	6	1,327,926	11	612,316	5
2001	13,292,524	1,845,162	14	561,009	4	1,284,153-	10-
TOTAL	123,089,242	11,113,927	9	7,864,651	6	3,249,276-	3-

THREE-YEAR MOVING AVERAGES

80-82	328,032	188,020	57	158,454	48	29,566-	9-
81-83	311,415	215,020	69	162,020	52	53,000-	17-
82-84	428,427	244,794	57	160,211	37	84,583-	20-
83-85	540,587	291,032	54	90,430	17	200,602-	37-
84-86	748,293	378,637	51	132,475	18	246,162-	33-
85-87	1,114,058	424,163	38	125,390	11	298,773-	27-
86-88	1,382,262	397,086	29	219,288	16	177,798-	13-
87-89	1,731,452	294,968	17	242,427	14	52,541-	3-
88-90	1,868,168	202,170	11	481,641	26	279,471	15
89-91	3,600,763	267,572	7	528,783	15	261,211	7
90-92	5,552,907	605,522	11	502,949	9	102,573-	2-
91-93	9,443,117	988,639	10	478,127	5	510,512-	5-
92-94	9,395,276	1,025,121	11	556,354	6	468,767-	5-
93-95	8,825,997	925,346	10	571,552	6	353,794-	4-
94-96	5,109,466	678,692	13	414,185	8	264,507-	5-
95-97	6,136,058	634,141	10	240,664	4	393,477-	6-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNTS 366 & 367 UNDERGROUND CONDUIT AND CONDUCTORS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	11,860,163	318,741	3	271,990	2	46,751-	0
97-99	14,443,673	200,144	1	263,301	2	63,157	0
98-00	15,215,929	286,616	2	640,574	4	353,958	2
99-01	11,901,103	922,706	8	720,539	6	202,167-	2-
FIVE-YEAR AVERAGE							
97-01	13,709,728	632,241	5	535,768	4	96,473-	1-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 368 LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1980	1,157,498	172,546	15	337,519	29	164,973	14
1981	2,552,557	557,033	22	372,452	15	184,581-	7-
1982	1,816,640	465,702	26	509,989	28	44,287	2
1983	884,736	265,250	30	180,269	20	84,981-	10-
1984	490,573	540,512	110	416,859	85	123,653-	25-
1985	3,021,486	684,612	23	539,379	18	145,233-	5-
1986	1,948,121	166,974	9	462,986	24	296,012	15
1987	3,659,664	20,889	1	166,627	5	145,738	4
1988	1,755,669	261,757	15	584,006	33	322,249	18
1989	1,902,762	224,108	12	581,253	31	357,145	19
1990	1,640,395	136,698	8	590,977	36	454,279	28
1991	1,042,782	307,026	29	450,835	43	143,809	14
1992	1,073,804	474,600	44	144,640	13	329,960-	31-
1993	1,204,068	551	0	114,674	10	114,123	9
1994	914,534	1	0	213,136	23	213,135	23
1995	1,065,132		0	175,694	16	175,694	16
1996	328,125	494	0	122,579	37	122,085	37
1997	3,326,918	1,019	0	245,785	7	244,766	7
1998	2,113	106-	5-	231,134		231,240	
1999	814,947	76	0	55,942	7	55,866	7
2000	4,287,170	2,387	0	223,765	5	221,378	5
2001	3,562,241	6,814	0	83,033	2	76,219	2
TOTAL	38,451,935	4,288,943	11	6,803,533	18	2,514,590	7

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
80-82	1,842,232	398,427	22	406,653	22	8,226	0
81-83	1,751,311	429,328	25	354,237	20	75,091-	4-
82-84	1,063,983	423,821	40	369,039	35	54,782-	5-
83-85	1,465,598	496,791	34	378,836	26	117,955-	8-
84-86	1,820,060	464,033	25	473,075	26	9,042	0
85-87	2,876,424	290,825	10	389,664	14	98,839	3
86-88	2,454,485	149,873	6	404,540	16	254,667	10
87-89	2,439,365	168,918	7	443,962	18	275,044	11
88-90	1,766,275	207,521	12	585,412	33	377,891	21
89-91	1,528,646	222,611	15	541,022	35	318,411	21
90-92	1,252,327	306,108	24	395,484	32	89,376	7
91-93	1,106,885	260,726	24	236,716	21	24,010-	2-
92-94	1,064,135	158,384	15	157,483	15	901-	0
93-95	1,061,245	184	0	167.835	16	167,651	16
94-96	769,264	165	0	170,470	22	170,305	22
95-97	1,573,392	504	0	181,353	12	180,849	11

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 368 LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	1,219,052	469	0	199,833	16	199,364	16
97-99	1,381,326	330	0	177,620	13	177,290	13
98-00	1,701,410	786	0	170,281	10	169,495	10
99-01	2,888,119	3,093	0	120,914	4	117,821	4
FIVE-YEAR AVERAGE							
97-01	2,398,678	2,038	0	167,932	7	165,894	7

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 369 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1980	148,715	32,990	22	4,295	3	28,695-	19-
1981	117,607	20,588	18	18,624	16	1,964-	2-
1982	136,928	37,308	27	10,214	7	27,094-	20-
1983	142,702	61,455	43	16,550	12	44,905-	31-
1984	91,352	67,218	74	20,201	22	47,017-	51-
1985	111,733	37,064	33	52,085	47	15,021	13
1986	163,844	16,906	10	5,888	4	11,018-	7-
1987	198,966	34,726	17	24,468	12	10,258-	5-
1988	17,673	116,858	661	149,154	844	32,296	183
1989	243,097	105,738	43	100,763	41	4,975-	2-
1990	157,106	31,184	20	44,752	28	13,568	9
1991	175,803	88,570	50	52,034	30	36,536-	21-
1992	252,863	170,337	67	33,851	13	136,486-	54-
1993	421,834	31,417	7	7,391	2	24,026-	6-
1994	154,803	19,893	13	26,364	17	6,471	4
1995	127,432	29,181	23	5,410	4	23,771-	19-
1996	51,664	17,556	34	10,984	21	6,572-	13-
1997	321,064	339	0	1,348	0	1,009	0
1998	157,202	1,249	1	4,016	3	2,767	2
1999	548,633	1,339	0	8,573	2	7,234	1
2000	868,132	9,557	1	46,603	5	37,046	4
2001	998,557	73,686	7	35,575	4	38,111-	4-
TOTAL	5,607,710	1,005,159	18	679,143	12	326,016-	6-

THREE-YEAR MOVING AVERAGES

80-82	134,417	30,295	23	11,044	8	19,251-	14-
81-83	132,412	39,784	30	15,129	11	24,655-	19-
82-84	123,661	55,327	45	15,655	13	39,672-	32-
83-85	115,262	55,246	48	29,612	26	25,634-	22-
84-86	122,310	40,396	33	26,058	21	14,338-	12-
85-87	158,181	29,565	19	27,480	17	2,085-	1-
86-88	126,828	56,163	44	59,837	47	3,674	3
87-89	153,245	85,774	56	91,462	60	5,688	4
88-90	139,292	84,593	61	98,223	71	13,630	10
89-91	192,002	75,164	39	65,850	34	9,314-	5-
90-92	195,257	96,697	50	43,546	22	53,151-	27-
91-93	283,500	96,775	34	31,092	11	65,683-	23-
92-94	276,500	73,882	27	22,535	8	51,347-	19-
93-95	234,690	26,830	11	13,055	6	13,775-	6-
94-96	111,300	22,210	20	14,253	13	7,957-	7-
95-97	166,720	15,692	9	5,914	4	9,778-	6-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 369 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	176,643	6,381	4	5,449	3	932-	1-
97-99	342,300	976	0	4,646	1	3,670	1
98-00	524,656	4,048	1	19,731	4	15,683	3
99-01	805,107	28,194	4	30,250	4	2,056	0
FIVE-YEAR AVERAGE							
97-01	578,718	17,234	3	19,223	3	1,989	0

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 370 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1980	236,982	57	0	16,722	7	16,665	7
1981	194,904		0	3,831	2	3,831	2
1982	110,403	82-	0	9,282	8	9,364	8
1983	525,769	7,203	1	4,726	1	2,477-	0
1984	286,472	206	0	6,136	2	5,930	2
1985	339,067		0	298	0	298	0
1986	789,827		0	50,892	6	50,892	6
1987	466,199		0	15,332	3	15,332	3
1988	422,027	13,674	3	45,030	11	31,356	7
1989	482,811	24,085	5	35,139	7	11,054	2
1990	619,622	32,142	5	38,831	6	6,689	1
1991	862,041	6,609	1	31,161	4	24,552	3
1992	3,797,834	32,001	1	97,971	3	65,970	2
1993	2,456,699		0	135,619	6	135,619	6
1994	4,272,797		0	11,530	0	11,530	0
1995	6,157,490		0	9,271	0	9,271	0
1996	4,531,550		0	28,049	1	28,049	1
1997	2,806,407		0	3,327	0	3,327	0
1998	2,511,441		0	1,554	0	1,554	0
1999	1,907,409		0	132	0	132	0
2000	2,950,791		0	1,357	0	1,357	0
2001	1,879,901		0	8,755	0	8,755	0
TOTAL	38,608,443	115,895	0	554,945	1	439,050	1

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
80-82	180,763	8-	0	9,945	6	9,953	6
81-83	277,025	2,374	1	5,946	2	3,572	1
82-84	307,548	2,442	1	6,715	2	4,273	1
83-85	383,769	2,470	1	3,720	1	1,250	0
84-86	471,789	69	0	19,109	4	19,040	4
85-87	531,698		0	22,174	4	22,174	4
86-88	559,351	4,558	1	37,085	7	32,527	6
87-89	457,012	12,586	3	31,834	7	19,248	4
88-90	508,153	23,300	5	39,667	8	16,367	3
89-91	654,825	20,945	3	35,044	5	14,099	2
90-92	1,759,832	23,584	1	55,988	3	32,404	2
91-93	2,372,191	12,870	1	88,250	4	75,380	3
92-94	3,509,110	10,667	0	81,707	2	71,040	2
93-95	4,295,662		0	52,140	1	52,140	1
94-96	4,987,279		0	16,283	0	16,283	0
95-97	4,498,482		0	13,549	0	13,549	0

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 370 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
96-98	3,283,133		0	10,977	0	10,977	0
97-99	2,408,419		0	1,671	0	1,671	0
98-00	2,456,547		0	1,014	0	1,014	0
99-01	2,246,034		0	3,415	0	3,415	0
FIVE-YEAR AVERAGE							
97-01	2,411,190		0	3,025	0	3,025	0

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS PREMISES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1980	98,714	25,328	26	11,588	12	13,740-	14-
1981	101,515	43,787	43	8,985	9	34,802-	34-
1982	147,644	50,689	34	12,012	8	38,677-	26-
1983	120,234	47,521	40	5,432	5	42,089-	35-
1984	134,638	64,325	48	523	0	63,802-	47-
1985	145,496	52,050	36	5,958	4	46,092-	32-
1986	124,288	54,632	44	1,334	1	53,298-	43-
1987	67,765	43,139	64	1,803	3	41,336-	61-
1988	94,843	45,160	48	17,961	19	27,199-	29-
1989	119,910	63,505	53	47,504	40	16,001-	13-
1990	130,177	29,939	23	32,675	25	2,736	2
1991	175,284	78,385	45	16,837	10	61,548-	35-
1992	204,423	44,153	22	8,923	4	35,230-	17-
1993	223,607	25,728	12	886	0	24,842-	11-
1994	114,441	21,196	19	1,811	2	19,385-	17-
1995	110,412	13,879-	13-	3,627	3	17,506	16
1996	104,371	18,693	18		0	18,693-	18-
1997	156,100	1,060	1		0	1,060-	1-
1998	91,651	4,173	5	3,568	4	605-	1-
1999	269,435	5,219	2	2,801	1	2,418-	1-
2000	281,111	36,149	13	59,088	21	22,939	8
2001	263,056	11,858	5	19,623-	7-	31,481-	12-
TOTAL	3,279,115	752,830	23	223,693	7	529,137-	16-

THREE-YEAR MOVING AVERAGES

80-82	115,958	39,935	34	10,862	9	29,073-	25-
81-83	123,131	47,332	38	8,810	7	38,522-	31-
82-84	134,172	54,178	40	5,989	4	48,189-	36-
83-85	133,456	54,632	41	3,971	3	50,661-	38-
84-86	134,807	57,002	42	2,605	2	54,397-	40-
85-87	112,516	49,940	44	3,032	3	46,908-	42-
86-88	95,632	47,644	50	7,033	7	40,611-	42-
87-89	94,173	50,601	54	22,423	24	28,178-	30-
88-90	114,977	46,201	40	32,713	28	13,488-	12-
89-91	141,790	57,276	40	32,339	23	24,937-	18-
90-92	169,961	50,826	30	19,478	11	31,348-	18-
91-93	201,105	49,422	25	8,882	4	40,540-	20-
92-94	180,824	30,359	17	3,873	2	26,486-	15-
93-95	149,487	11,015	7	2,108	1	8,907-	6-
94-96	109,741	8,670	8	1,813	2	6,857-	6-
95-97	123,628	1,965	2	1,209	1	756-	1-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS PREMISES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	117,374	7,982	7	1,189	1	6,793-	6-
97-99	172,395	3,491	2	2,123	1	1,368-	1-
98-00	214,065	15,180	7	21,819	10	6,639	3
99-01	271,201	17,742	7	14,089	5	3,653-	1-
FIVE-YEAR AVERAGE							
97-01	212,271	11,696	6	9,167	4	2,529-	1-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1980	230,490	39,493	17	101,134	44	61,641	27
1981	305,377	59,022	19	188,002	62	128,980	42
1982	147,607	80,272	54	123,265	84	42,993	29
1983	158,377	41,728	26	93,025	59	51,297	32
1984	255,028	50,999	20	43,857	17	7,142-	3-
1985	177,821	33,991	19	52,453	29	18,462	10
1986	403,630	109,189	27	66,610	17	42,579-	11-
1987	473,970	83,499	18	33,392	7	50,107-	11-
1988	545,186	225,711	41	262,489	48	36,778	7
1989	527,460	198,202	38	229,631	44	31,429	6
1990	311,244	56,624	18	172,416	55	115,792	37
1991	428,284	414,347	97	375,256	88	39,091-	9-
1992	344,692	113,179	33	52,057	15	61,122-	18-
1993	399,733	46,666	12	17,258	4	29,408-	7-
1994	207,368	60,457	29	20,803	10	39,654-	19-
1995	197,106	108,678	55	52,328	27	56,350-	29-
1996	70,371	33,158	47	37,991	54	4,833	7
1997		18,224		5,905		12,319-	
1998	384,965	4,927-	1-	51,796	13	56,723	15
1999	60,395	59,051	98	35,055	58	23,996-	40-
2000	494,881	20,142	4	53,147	11	33,005	7
2001	334,618	45,479	14	115,609	35	70,130	21
TOTAL	6,458,603	1,893,184	29	2,183,479	34	290,295	4

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
80-82	227,825	59,596	26	137,467	60	77,871	34
81-83	203,787	60,341	30	134,764	66	74,423	37
82-84	187,004	57,666	31	86,716	46	29,050	16
83-85	197,075	42,239	21	63,112	32	20,873	11
84-86	278,826	64,726	23	54,307	19	10,419-	4-
85-87	351,807	75,560	21	50,818	14	24,742-	7-
86-88	474,262	139,466	29	120,830	25	18,636-	4-
87-89	515,539	169,137	33	175,171	34	6,034	1
88-90	461,297	160,179	35	221,512	48	61,333	13
89-91	422,329	223,058	53	259,101	61	36,043	9
90-92	361,407	194,717	54	199,910	55	5,193	1
91-93	390,903	191,397	49	148,190	38	43,207-	11-
92-94	317,264	73,434	23	30,039	9	43,395-	14-
93-95	268,069	71,934	27	30,130	11	41,804-	16-
94-96	158,282	67,431	43	37,041	23	30,390-	19-
95-97	89,159	53,353	60	32,074	36	21,279-	24-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	151,779	15,485	10	31,897	21	16,412	11
97-99	148,454	24,116	16	30,919	21	6,803	5
98-00	313,414	24,755	8	46,666	15	21,911	7
99-01	296,631	41,557	14	67,937	23	26,380	9
FIVE-YEAR AVERAGE							
97-01	254,972	27,594	11	52,302	21	24,708	10

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1980	4,500		0		0		0
1981							
1982	492		0		0		0
1983	28,600		0		0		0
1984							
1985	75,176	6,912	9	2,377	3	4,535-	6-
1986	193,331	38,466	20	961	0	37,505-	19-
1987	554,698	6,072	1	57	0	6,015-	1-
1988	1,758,903	44,115	3	16,211	1	27,904-	2-
1989	4,600,937	4,006	0	66,961	1	62,955	1
1990	1,567,998	447,799	29	5,711	0	442,088-	28-
1991	124,431	252,312	203	827	1	251,485-	202-
1992	246,656	334,006	135		0	334,006-	135-
1993	471,262	675,248	143	33,700	7	641,548-	136-
1994	468,723	564,881	121		0	564,881-	121-
1995	1,787,639	476,459	27		0	476,459-	27-
1996	911,551	150,718	17		0	150,718-	17-
1997		3,100				3,100-	
1998	28,592	99,331	347	10,948	38	88,383-	309-
1999	262,727	133,725	51	52,870	20	80,855-	31-
2000	32,461	5,097	16	1,649	5	3,448-	11-
2001	770,978	13,837-	2-	48,610	6	62,447	8
TOTAL	13,889,655	3,228,410	23	240,882	2	2,987,528-	22-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
80-82	1,664		0		0		0
81-83	9,697		0		0		0
82-84	9,697		0		0		0
83-85	34,592	2,304	7	792	2	1,512-	4-
84-86	89,502	15,126	17	1,113	1	14,013-	16-
85-87	274,402	17,150	6	1,132	0	16,018-	6-
86-88	835,644	29,551	4	5,743	1	23,808-	3-
87-89	2,304,846	18,064	1	27,743	1	9,679	0
88-90	2,642,613	165,307	6	29,628	1	135,679-	5-
89-91	2,097,789	234,706	11	24,500	1	210,206-	10-
90-92	646,362	344,706	53	2,179	0	342,527-	53-
91-93	280,783	420,522	150	11,509	4	409,013-	146-
92-94	395,547	524,712	133	11,233	3	513,479-	130-
93-95	909,208	572,196	63	11,233	1	560,963-	62-
94-96	1,055,971	397,353	38		0	397,353-	38-
95-97	899,730	210,092	23		0	210,092-	23-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
96-98	313,381	84,383	27	3,649	1	80,734-	26-
97-99	97,107	78,719	81	21,273	22	57,446-	59-
98-00	107,927	79,384	74	21,822	20	57,562-	53-
99-01	355,389	41,662	12	34,376	10	7,286-	2-
FIVE-YEAR AVERAGE							
97-01	218,952	45,483	21	22,816	10	22,667-	10-

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1981	75		0		0		0
1982							
1983	750		0		0		0
1984	17,941		0		0		0
1985	53,553	9,456	18	20,021	37	10,565	20
1986	25,494	955	4	14,221	56	13,266	52
1987	58,327	30,043	52	11,417	20	18,626-	32-
1988	114,580	1,318	1	89,444	78	88,126	77
1989	1,394,247	19,526	1	202,422	15	182,896	13
1990	107,117	2,812	3	8,087	8	5,275	5
1991	10,001		0	16,389	164	16,389	164
1992	77,697	795-	1-	738	1	1,533	2
1993		684		15,924		15,240	
1994	92,142		0	82,149	89	82,149	89
1995	84,048		0	10,000	12	10,000	12
1996	1,392,845		0		0		0
1997	17,830,894		0	142-	0	142-	0
1998	4,824,424		0		0		0
1999	14,705,340		0		0		0
2000	4,186,877		0	14	0	14	0
2001	117,584	106,175-	90-		0	106,175	90
TOTAL	45,093,936	42,176-	0	470,684	1	512,860	1

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
81-83	275		0		0		0
82-84	6,230		0		0		0
83-85	24,081	3,152	13	6,674	28	3,522	15
84-86	32,329	3,470	11	11,414	35	7,944	25
85-87	45,791	13,485	29	15,220	33	1,735	4
86-88	66,134	10,772	16	38,361	58	27,589	42
87-89	522,385	16,962	3	101,094	19	84,132	16
88-90	538,648	7,885	1	99,984	19	92,099	17
89-91	503,788	7,446	1	75,633	15	68,187	14
90-92	64,938	672	1	8,405	13	7,733	12
91-93	29,233	37-	0	11,017	38	11,054	38
92-94	56,613	37-	0	32,937	58	32,974	58
93-95	58,730	228	0	36,024	61	35,796	61
94-96	523,012		0	30,716	6	30,716	6
95-97	6,435,929		0	3,286	0	3,286	0
96-98	8,016,054		0	47-	0	47-	0
97-99	12,453,553		0	47-	0	47-	0

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
98-00	7,905,547		0	5	0	5	0
99-01	6,336,600	35,392-	1-	5	0	35,397	1
FIVE-YEAR AVERAGE							
97-01	8,333,024	21,235-	0	26-	0	21,209	0

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - PC EQUIP

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1984	53,926	0		0		0	
1985	1,301,518	0		0		0	
1986	2,368,532	0		0		0	
1987	1,668,901	0		0		0	
1988	952,707	0		0		0	
1989	252,771	0		0		0	
1990	52,588	0		0		0	
1991	574,052	0		0		0	
1992	18,873,181	0		0		0	
1993	4,121,773	0		0		0	
1994	11,315,065	0		0		0	
1995	24,120,771	0		0		0	
1996	7,884,362	0		0		0	
1997							
1998							
1999							
2000							
2001							
TOTAL	73,540,147	0		0		0	

THREE-YEAR MOVING AVERAGES

84-86	1,241,325	0		0		0	
85-87	1,779,650	0		0		0	
86-88	1,663,380	0		0		0	
87-89	958,126	0		0		0	
88-90	419,355	0		0		0	
89-91	293,137	0		0		0	
90-92	6,499,940	0		0		0	
91-93	7,856,335	0		0		0	
92-94	11,436,673	0		0		0	
93-95	13,185,870	0		0		0	
94-96	14,440,066	0		0		0	
95-97	10,668,378	0		0		0	
96-98	2,628,121	0		0		0	
97-99							
98-00							
99-01							

FIVE-YEAR AVERAGE

97-01

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1984	6,930	0		0		0	
1985	74,042	0		0		0	
1986	26,628	0		0		0	
1987	82,199	0		0		0	
1988	219,491	0		0		0	
1989	47,385	0		0		0	
1990	57,854	0		0		0	
1991	1	0		0		0	
1992							
1993	3,060	0		0		0	
1994	269,849	0		0		0	
1995	119,892	0		0		0	
1996							
1997							
1998							
1999							
2000							
2001							
TOTAL	907,331	0		0		0	

THREE-YEAR MOVING AVERAGES

84-86	35,867	0		0		0	
85-87	60,956	0		0		0	
86-88	109,439	0		0		0	
87-89	116,358	0		0		0	
88-90	108,243	0		0		0	
89-91	35,080	0		0		0	
90-92	19,285	0		0		0	
91-93	1,020	0		0		0	
92-94	90,970	0		0		0	
93-95	130,934	0		0		0	
94-96	129,914	0		0		0	
95-97	39,964	0		0		0	
96-98							
97-99							
98-00							
99-01							

FIVE-YEAR AVERAGE

97-01

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 393 STORES EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1992	74,134		0		0		0
1993							
1994	600		0		0		0
1995							
1996							
1997							
1998							
1999							
2000							
2001	26,374		0		0		0
TOTAL	101,108		0		0		0
THREE-YEAR MOVING AVERAGES							
92-94	24,911		0		0		0
93-95	200		0		0		0
94-96	200		0		0		0
95-97							
96-98							
97-99							
98-00							
99-01	8,791		0		0		0
FIVE-YEAR AVERAGE							
97-01	5,275		0		0		0

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1980	3,408		0		0		0
1981	22,507		0		0		0
1982	2,580		0		0		0
1983	11,806		0		0		0
1984							
1985	7,975		0	581	7	581	7
1986	4,482		0		0		0
1987	14,148		0	512	4	512	4
1988	1,125	13	1	816	73	803	71
1989		2,037		5		2,032-	
1990		2,302		20		2,282-	
1991	1		0	1,371		1,371	
1992							
1993	54,255		0	400	1	400	1
1994	2,581		0		0		0
1995	8,519		0	1,575	18	1,575	18
1996	10,414,896		0	9,271	0	9,271	0
1997	54,663		0	4,393	8	4,393	8
1998				1,981		1,981	
1999	1,467		0		0		0
2000							
2001	19,273		0		0		0
TOTAL	10,623,686	4,352	0	20,925	0	16,573	0
THREE-YEAR MOVING AVERAGES							
80-82	9,498		0		0		0
81-83	12,298		0		0		0
82-84	4,795		0		0		0
83-85	6,594		0	194	3	194	3
84-86	4,152		0	194	5	194	5
85-87	8,868		0	364	4	364	4
86-88	6,585	4	0	443	7	439	7
87-89	5,091	683	13	444	9	239-	5-
88-90	375	1,451	387	280	75	1,171-	312-
89-91		1,446		465		981-	
90-92		767		464		303-	
91-93	18,085		0	590	3	590	3
92-94	18,945		0	133	1	133	1
93-95	21,785		0	658	3	658	3
94-96	3,475,332		0	3,615	0	3,615	0
95-97	3,492,693		0	5,080	0	5,080	0

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	3,489,853		0	5,215	0	5,215	0
97-99	18,710		0	2,124	11	2,124	11
98-00	489		0	660	135	660	135
99-01	6,913		0		0		0
FIVE-YEAR AVERAGE							
97-01	15,081		0	1,275	8	1,275	8

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 395 LABORATORY EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1983	500		0		0		0
1984							
1985							
1986							
1987	10,000		0		0		0
1988							
1989							
1990	372,413		0		0		0
1991							
1992							
1993							
1994	16,007		0		0		0
1995							
1996							
1997							
1998							
1999							
2000							
2001							
TOTAL	398,920		0		0		0

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
83-85	167		0		0		0
84-86							
85-87	3,333		0		0		0
86-88	3,333		0		0		0
87-89	3,333		0		0		0
88-90	124,138		0		0		0
89-91	124,138		0		0		0
90-92	124,138		0		0		0
91-93							
92-94	5,336		0		0		0
93-95	5,336		0		0		0
94-96	5,336		0		0		0
95-97							
96-98							
97-99							
98-00							
99-01							

FIVE-YEAR AVERAGE

97-01

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 397 COMMUNICATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1980	188,179		0		0		0
1981	103,749		0		0		0
1982	119,188		0		0		0
1983	29,516		0		0		0
1984	181,773		0		0		0
1985	170,157	8,190	5	1,547	1	6,643-	4-
1986	256,834	20,878	8	34,839	14	13,961	5
1987	223,006	4,706	2	9,852	4	5,146	2
1988	2,366,371	9,548	0	54,704	2	45,156	2
1989	271,451	12,121	4	18,189	7	6,068	2
1990	1,191,779	29,179	2	3,514	0	25,665-	2-
1991	205,368	13,258	6	40	0	13,218-	6-
1992	423,495	27,061	6		0	27,061-	6-
1993	223,593	8,405	4		0	8,405-	4-
1994	558,424	5,377	1		0	5,377-	1-
1995	2,410,094	52,766	2	126,458	5	73,692	3
1996	4,320,865	60	0		0	60-	0
1997	5,831,203	18	0		0	18-	0
1998		97,091				97,091-	
1999	8,543,077	5,263-	0	119,336	1	124,599	1
2000	5,488,147		0	561,385	10	561,385	10
2001	921,103	77,559-	8-		0	77,559	8
TOTAL	34,027,372	205,836	1	929,864	3	724,028	2

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
80-82	137,039		0		0		0
81-83	84,151		0		0		0
82-84	110,159		0		0		0
83-85	127,149	2,730	2	516	0	2,214-	2-
84-86	202,921	9,689	5	12,129	6	2,440	1
85-87	216,666	11,258	5	15,413	7	4,155	2
86-88	948,737	11,711	1	33,132	3	21,421	2
87-89	953,609	8,792	1	27,582	3	18,790	2
88-90	1,276,534	16,949	1	25,469	2	8,520	1
89-91	556,199	18,186	3	7,248	1	10,938-	2-
90-92	606,881	23,166	4	1,185	0	21,981-	4-
91-93	284,152	16,241	6	13	0	16,228-	6-
92-94	401,837	13,614	3		0	13,614-	3-
93-95	1,064,037	22,183	2	42,153	4	19,970	2
94-96	2,429,794	19,401	1	42,153	2	22,752	1
95-97	4,187,387	17,615	0	42,153	1	24,538	1

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 397 COMMUNICATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	3,384,023	32,390	1		0	32,390-	1-
97-99	4,791,427	30,616	1	39,779	1	9,163	0
98-00	4,677,075	30,610	1	226,907	5	196,297	4
99-01	4,984,109	27,607-	1-	226,907	5	254,514	5
FIVE-YEAR AVERAGE							
97-01	4,156,706	2,858	0	136,144	3	133,286	3

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1982	2,000		0		0		0
1983	11,000		0		0		0
1984	11,000-		0		0		0
1985							
1986	10,750		0		0		0
1987	4,600		0		0		0
1988							
1989	768	34,452		401	52	34,051-	
1990	6,436	619	10	47-	1-	666-	10-
1991							
1992	653,536	2,845-	0	444	0	3,289	1
1993	4,080	704	17		0	704-	17-
1994	175,170		0		0		0
1995							
1996							
1997							
1998							
1999	14,899		0		0		0
2000							
2001	5,878		0		0		0
TOTAL	878,117	32,930	4	798	0	32,132-	4-
THREE-YEAR MOVING AVERAGES							
82-84	667		0		0		0
83-85							
84-86	83-		0		0		0
85-87	5,117		0		0		0
86-88	5,117		0		0		0
87-89	1,789	11,484	642	134	7	11,350-	634-
88-90	2,401	11,690	487	118	5	11,572-	482-
89-91	2,401	11,690	487	118	5	11,572-	482-
90-92	219,991	742-	0	132	0	874	0
91-93	219,205	714-	0	148	0	862	0
92-94	277,595	714-	0	148	0	862	0
93-95	59,750	235	0		0	235-	0
94-96	58,390		0		0		0
95-97							
96-98							
97-99	4,966		0		0		0
98-00	4,966		0		0		0
99-01	6,926		0		0		0
FIVE-YEAR AVERAGE							
97-01	4,155		0		0		0

APPENDIX C

DEPRECIATION CALCULATIONS

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHOLLA UNIT 1 INTERIM SURVIVOR CURVE.. IOWA 75-S1.5 PROBABLE RETIREMENT YEAR.. 6-2017 NET SALVAGE PERCENT.. -20						
1962	987,438	874,712	1,030,082	154,844	13.49	11,478
1964	455	398	469	77	13.57	6
1966	6,033	5,197	6,120	1,120	13.65	82
1971	1,320	1,089	1,282	302	13.84	22
1972	1,878	1,533	1,805	449	13.87	32
1975	82,872	65,366	76,977	22,469	13.97	1,608
1976	547,491	426,320	502,045	154,944	14.00	11,067
1979	64,304	47,904	56,413	20,752	14.09	1,473
1981	7,314	5,263	6,198	2,579	14.14	182
1982	47,175	33,287	39,200	17,410	14.17	1,229
1983	28,716	19,845	23,370	11,089	14.19	781
1985	58,195	38,332	45,141	24,693	14.24	1,734
1986	6,028	3,865	4,552	2,682	14.26	188
1988	103,286	62,207	73,256	50,687	14.30	3,545
1990	22,340	12,452	14,664	12,144	14.34	847
1994	92,677	41,215	48,535	62,677	14.40	4,353
1995	34,644	14,218	16,744	24,829	14.41	1,723
1996	451	168	198	343	14.42	24
1998	45,778	13,025	15,338	39,596	14.45	2,740
1999	6,394	1,492	1,757	5,916	14.46	409
	2,144,789	1,667,888	1,964,146	609,602		43,523
CHOLLA UNIT 2 INTERIM SURVIVOR CURVE.. IOWA 75-S1.5 PROBABLE RETIREMENT YEAR.. 6-2033 NET SALVAGE PERCENT.. -20						
1978	2,656,974	1,464,737	1,805,727	1,382,642	27.85	49,646
1981	23,841	12,179	15,014	13,595	28.25	481
1982	11,705	5,811	7,164	6,882	28.37	243
1985	80,109	36,001	44,382	51,749	28.73	1,801
1986	71,386	30,873	38,060	47,603	28.84	1,651

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHOLLA UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 75-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2033						
NET SALVAGE PERCENT.. -20						
1987	47,868	19,852	24,474	32,968	28.95	1,139
1988	251,979	99,814	123,051	179,324	29.06	6,171
1994	2,172	579	714	1,892	29.61	64
1995	34,644	8,356	10,301	31,272	29.69	1,053
1996	451	97	120	421	29.76	14
1998	1,372,451	215,091	265,163	1,381,778	29.90	46,213
1999	6,394	803	990	6,683	29.96	223
2002	462,205	9,041	11,146	543,500	30.12	18,044
	5,022,179	1,903,234	2,346,306	3,680,309		126,743
CHOLLA UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 75-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -20						
1980	8,586,605	4,365,773	5,684,369	4,619,557	29.69	155,593
1981	23,841	11,790	15,351	13,258	29.84	444
1982	11,705	5,621	7,319	6,727	29.98	224
1985	126,987	55,026	71,645	80,739	30.40	2,656
1986	369,860	154,054	200,583	243,249	30.53	7,968
1987	47,864	19,109	24,880	32,557	30.65	1,062
1988	170,215	64,872	84,465	119,793	30.77	3,893
1994	2,169	552	719	1,884	31.41	60
1995	34,644	7,978	10,388	31,185	31.50	990
1996	466	95	124	435	31.59	14
1998	47,165	7,012	9,129	47,469	31.75	1,495
1999	6,588	783	1,020	6,886	31.82	216
2002	155,168	2,868	3,734	182,468	32.02	5,699
	9,583,277	4,695,533	6,113,726	5,386,207		180,314

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHOLLA COMMON INTERIM SURVIVOR CURVE.. IOWA 75-S1.5 PROBABLE RETIREMENT YEAR.. 6-2035 NET SALVAGE PERCENT.. -20						
1962	489,320	340,978	447,296	139,888	26.50	5,279
1978	15,761,056	8,433,426	11,062,999	7,850,268	29.38	267,198
1979	8,595	4,487	5,886	4,428	29.54	150
1980	2,755,752	1,401,135	1,838,014	1,468,888	29.69	49,474
1981	5,522,881	2,731,175	3,582,765	3,044,692	29.84	102,034
1982	5,244,827	2,518,776	3,304,140	2,989,652	29.98	99,722
1983	139,618	64,922	85,165	82,377	30.13	2,734
1984	2,325,172	1,045,490	1,371,478	1,418,728	30.26	46,885
1985	474,156	205,461	269,524	299,463	30.40	9,851
1986	106,949	44,546	58,436	69,903	30.53	2,290
1987	58,210	23,240	30,486	39,366	30.65	1,284
1988	305,051	116,261	152,512	213,549	30.77	6,940
1990	26,921	9,220	12,095	20,210	31.00	652
1991	187,718	60,433	79,283	145,979	31.11	4,692
1992	633,701	190,262	249,586	510,855	31.22	16,363
1993	585,068	162,602	213,302	488,780	31.32	15,606
1996	136,275	27,833	36,511	127,019	31.59	4,021
1997	264,457	46,872	61,487	255,861	31.67	8,079
2000	660,445	57,617	75,582	716,952	31.89	22,482
2002	548,378	10,134	13,294	644,760	32.02	20,136
	36,234,550	17,494,875	22,949,841	20,531,618		685,872
FOUR CORNERS UNITS 1-3 INTERIM SURVIVOR CURVE.. IOWA 75-S1.5 PROBABLE RETIREMENT YEAR.. 6-2016 NET SALVAGE PERCENT.. -20						
1963	913,885	818,658	629,072	467,590	12.67	36,905
1964	364,219	324,213	249,131	187,932	12.70	14,798
1965	135,524	119,809	92,063	70,566	12.74	5,539
1966	22,048	19,356	14,874	11,584	12.77	907
1967	38,745	33,755	25,938	20,556	12.81	1,605

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FOUR CORNERS UNITS 1-3						
INTERIM SURVIVOR CURVE.. IOWA 75-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2016						
NET SALVAGE PERCENT.. -20						
1968	2,491	2,153	1,654	1,335	12.84	104
1969	12,777	10,957	8,420	6,912	12.87	537
1971	16,727	14,089	10,826	9,246	12.93	715
1972	10,399	8,673	6,664	5,815	12.97	448
1973	12,656	10,449	8,029	7,158	12.99	551
1974	121,527	99,254	76,269	69,563	13.02	5,343
1975	19,280	15,564	11,960	11,176	13.05	856
1976	78,277	62,409	47,956	45,976	13.08	3,515
1978	657,380	510,153	392,011	396,845	13.13	30,224
1979	735,101	561,999	431,851	450,270	13.15	34,241
1980	564,006	424,223	325,981	350,826	13.18	26,618
1981	330,716	244,545	187,913	208,946	13.20	15,829
1982	568,236	412,471	316,950	364,933	13.22	27,605
1983	574,536	408,771	314,107	375,336	13.24	28,349
1984	719,153	500,530	384,617	478,367	13.26	36,076
1985	2,093,283	1,422,511	1,093,084	1,418,856	13.28	106,842
1986	2,045,834	1,354,424	1,040,765	1,414,236	13.30	106,334
1987	69,908	44,973	34,558	49,332	13.32	3,704
1988	218,258	135,957	104,472	157,438	13.34	11,802
1989	70,176	42,232	32,452	51,759	13.35	3,877
1990	133,336	77,122	59,262	100,741	13.37	7,535
1991	476,691	263,934	202,812	369,217	13.38	27,595
1992	2,979	1,569	1,206	2,369	13.39	177
1993	1,325,525	658,362	505,897	1,084,733	13.41	80,890
1994	160,127	74,401	57,171	134,981	13.42	10,058
1995	432,230	185,686	142,685	375,991	13.43	27,996
1996	1,080,840	422,306	324,507	972,501	13.44	72,359
1998	107,041	32,125	24,685	103,764	13.46	7,709
1999	930,876	230,559	177,166	939,885	13.46	69,828
2000	103,059	19,354	14,872	108,799	13.47	8,077
2001	283,213	34,020	26,142	313,714	13.48	23,273
2002	541,868	23,279	17,888	632,354	13.48	46,911
	15,972,927	9,624,845	7,395,910	11,771,602		885,732

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FOUR CORNERS COMMON INTERIM SURVIVOR CURVE.. IOWA 75-S1.5 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -20						
1963	449,118	323,149	447,012	91,930	24.18	3,802
1964	580,435	412,898	571,162	125,360	24.34	5,150
1977	784,577	456,624	631,648	309,844	26.14	11,853
1979	1,050,433	584,503	808,543	451,977	26.38	17,133
1994	684,379	191,681	265,153	556,102	27.78	20,018
1995	23	6	8	20	27.84	1
1996	48,639	10,996	15,211	43,156	27.91	1,546
1997	15,919	3,135	4,337	14,766	27.97	528
1998	41,837	6,948	9,611	40,593	28.02	1,449
1999	158,944	21,152	29,259	161,474	28.07	5,753
2001	91,469	5,554	7,683	102,080	28.17	3,624
2002	41,098	858	1,187	48,131	28.21	1,706
	3,946,871	2,017,504	2,790,814	1,945,433		72,563
FOUR CORNERS UNITS 4-5 INTERIM SURVIVOR CURVE.. IOWA 75-S1.5 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -20						
1965	11,206	7,881	8,920	4,527	24.49	185
1969	227,829	152,172	172,239	101,156	25.08	4,033
1970	393,797	259,292	293,485	179,071	25.22	7,100
1971	337,247	218,698	247,538	157,158	25.36	6,197
1972	9,664	6,171	6,985	4,612	25.49	181
1973	18,861	11,842	13,404	9,229	25.63	360
1974	64,717	39,925	45,190	32,470	25.76	1,260
1975	1,587	961	1,088	816	25.89	32
1976	53,763	31,935	36,146	28,370	26.02	1,090
1978	233,586	133,032	150,575	129,728	26.26	4,940
1979	249,176	138,651	156,935	142,076	26.38	5,386
1980	29,556	16,045	18,161	17,306	26.50	653
1981	1,590,353	841,042	951,950	956,474	26.61	35,944

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FOUR CORNERS UNITS 4-5 INTERIM SURVIVOR CURVE.. IOWA 75-S1.5 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -20						
1982	871,816	448,392	507,521	538,658	26.72	20,159
1983	73,613	36,756	41,603	46,733	26.82	1,742
1984	4,242,649	2,050,727	2,321,157	2,770,022	26.93	102,860
1985	55,451	25,885	29,298	37,243	27.03	1,378
1986	58,689	26,382	29,861	40,566	27.13	1,495
1987	41,329	17,844	20,197	29,398	27.22	1,080
1988	7,699	3,179	3,598	5,641	27.31	207
1989	65,843	25,900	29,316	49,696	27.40	1,814
1990	3,724	1,389	1,572	2,897	27.48	105
1991	2,619	921	1,042	2,101	27.56	76
1992	60,137	19,773	22,381	49,783	27.64	1,801
1993	332,854	101,574	114,969	284,456	27.71	10,265
1994	64,378	18,031	20,409	56,845	27.78	2,046
1996	6,070	1,372	1,553	5,731	27.91	205
1999	32,297	4,298	4,864	33,892	28.07	1,207
2002	55,075	1,150	1,302	64,788	28.21	2,297
	9,195,585	4,641,220	5,253,259	5,781,443		216,098
NAVAJO UNITS 1-3 INTERIM SURVIVOR CURVE.. IOWA 75-S1.5 PROBABLE RETIREMENT YEAR.. 6-2026 NET SALVAGE PERCENT.. -20						
1974	2,327,062	1,555,967	1,600,120	1,192,354	21.78	54,745
1975	3,025,038	1,990,354	2,046,833	1,583,213	21.86	72,425
1976	3,895,313	2,518,086	2,589,540	2,084,836	21.95	94,981
1977	328,968	208,789	214,714	180,048	22.03	8,173
1978	583,152	362,907	373,205	326,577	22.11	14,771
1979	130,615	79,607	81,866	74,872	22.19	3,374
1980	168,986	100,702	103,560	99,223	22.27	4,455
1982	20,024	11,358	11,680	12,349	22.42	551
1983	256,238	141,413	145,426	162,060	22.49	7,206

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NAVAJO UNITS 1-3						
INTERIM SURVIVOR CURVE.. IOWA 75-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2026						
NET SALVAGE PERCENT.. -20						
1984	116,910	63,755	65,564	77,128	22.55	3,420
1985	101,044	52,466	53,955	67,298	22.62	2,975
1986	55,403	27,803	28,592	37,892	22.68	1,671
1987	391,580	189,227	194,597	275,299	22.74	12,106
1988	137,843	63,915	65,729	99,683	22.80	4,372
1991	253,715	101,202	104,074	200,384	22.96	8,728
1992	25,943	9,722	9,998	21,134	23.01	918
1993	30,608	10,685	10,988	25,742	23.06	1,116
1994	531,821	171,225	176,084	462,101	23.10	20,004
1995	275,373	80,728	83,019	247,429	23.14	10,693
1996	68,750	18,043	18,555	63,945	23.18	2,759
1997	13,855,835	3,179,083	3,269,292	13,357,710	23.22	575,267
1998	521,863	101,388	104,264	521,972	23.25	22,450
1999	48,433	7,596	7,812	50,308	23.28	2,161
	27,152,517	11,046,021	11,359,467	21,223,557		929,321
OCOTILLO UNITS 1-2						
INTERIM SURVIVOR CURVE.. IOWA 75-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2020						
NET SALVAGE PERCENT.. -20						
1960	767,241	656,267	654,364	266,325	15.85	16,803
1961	74,528	63,319	63,135	26,299	15.91	1,653
1962	2,000	1,687	1,682	718	15.97	45
1964	3,922	3,257	3,248	1,458	16.10	91
1965	2,826	2,327	2,320	1,071	16.16	66
1971	72,614	56,404	56,240	30,897	16.49	1,874
1972	2,153	1,653	1,648	936	16.54	57
1973	7,973	6,048	6,030	3,538	16.59	213
1974	17,824	13,344	13,305	8,084	16.64	486
1975	14,138	10,442	10,412	6,554	16.68	393
1979	2,608	1,806	1,801	1,329	16.86	79

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
OCOTILLO UNITS 1-2						
INTERIM SURVIVOR CURVE.. IOWA 75-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2020						
NET SALVAGE PERCENT.. -20						
1981	40,512	26,981	26,903	21,711	16.94	1,282
1982	43,808	28,551	28,468	24,102	16.98	1,419
1983	95,844	61,003	60,826	54,187	17.02	3,184
1985	40,991	24,747	24,675	24,514	17.09	1,434
1988	943,521	516,068	514,572	617,653	17.18	35,952
1990	153,014	76,917	76,694	106,923	17.24	6,202
1991	27,677	13,245	13,207	20,005	17.26	1,159
1992	69,678	31,497	31,406	52,208	17.29	3,020
1993	128,052	54,335	54,177	99,485	17.31	5,747
1994	190,178	74,991	74,774	153,440	17.33	8,854
1999	373,186	74,921	74,704	373,119	17.42	21,419
2000	545,630	82,106	81,867	572,889	17.43	32,868
2002	168,054	5,626	5,610	196,055	17.45	11,235
	3,787,972	1,887,542	1,882,068	2,663,500		155,535
SAGUARO UNITS 1-2						
INTERIM SURVIVOR CURVE.. IOWA 75-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2014						
NET SALVAGE PERCENT.. -20						
1954	857,167	830,081	926,562	102,038	10.65	9,581
1957	2,083	1,993	2,225	275	10.74	26
1963	2,787	2,590	2,891	453	10.91	42
1965	13,185	12,113	13,521	2,301	10.96	210
1969	1,991	1,780	1,987	402	11.06	36
1971	199,545	175,616	196,028	43,426	11.10	3,912
1979	14,618	11,798	13,169	4,373	11.26	388
1982	87,344	67,258	75,075	29,738	11.31	2,629
1983	4,553	3,444	3,844	1,620	11.32	143
1984	2,173	1,611	1,798	810	11.34	71
1985	26,518	19,243	21,480	10,342	11.35	911
1987	380,370	262,501	293,012	163,432	11.38	14,361

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SAGUARO UNITS 1-2						
INTERIM SURVIVOR CURVE.. IOWA 75-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2014						
NET SALVAGE PERCENT.. -20						
1989	65,945	42,819	47,796	31,338	11.40	2,749
1990	80,206	50,222	56,059	40,188	11.41	3,522
1991	19,773	11,885	13,266	10,462	11.42	916
1993	29,708	16,156	18,034	17,616	11.44	1,540
1994	64,302	32,833	36,649	40,513	11.45	3,538
1996	594,564	257,993	287,981	425,496	11.46	37,129
	2,446,832	1,801,936	2,011,377	924,823		81,704
YUCCA UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 75-S1.5						
PROBABLE RETIREMENT YEAR.. 12-2016						
NET SALVAGE PERCENT.. -20						
1959	428,565	389,617	447,787	66,491	12.94	5,138
1976	3,690	2,907	3,341	1,087	13.54	80
1984	10,026	6,872	7,898	4,133	13.74	301
1987	9,267	5,863	6,738	4,382	13.80	318
1995	11,019	4,625	5,316	7,907	13.92	568
	462,567	409,884	471,080	84,000		6,405
	115,950,066	57,190,482	64,537,994	74,602,094		3,383,810

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 22.0 2.92

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHOLLA UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 48-L2						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. -20						
1962	7,751,728	6,869,581	7,476,885	1,825,189	11.09	164,580
1964	5,759	5,056	5,503	1,408	11.20	126
1965	6,260	5,467	5,950	1,562	11.26	139
1966	29,363	25,504	27,759	7,477	11.32	661
1967	91,912	79,335	86,349	23,945	11.39	2,102
1969	2,354	2,005	2,182	643	11.53	56
1970	9,249	7,816	8,507	2,592	11.62	223
1971	16,679	13,980	15,216	4,799	11.70	410
1973	7,871	6,475	7,047	2,398	11.89	202
1974	5,801,655	4,723,011	5,140,548	1,821,438	11.99	151,913
1975	17,720	14,260	15,521	5,743	12.10	475
1979	55,518	42,225	45,958	20,664	12.57	1,644
1980	88,328	66,023	71,860	34,134	12.70	2,688
1982	3,978	2,860	3,113	1,661	12.95	128
1983	187,488	131,909	143,570	81,416	13.07	6,229
1984	38,059	26,128	28,438	17,233	13.20	1,306
1985	168,969	113,000	122,990	79,773	13.32	5,989
1986	864,700	562,401	612,120	425,520	13.43	31,684
1987	543,710	342,929	373,245	279,207	13.53	20,636
1988	1,016,644	619,624	674,402	545,571	13.63	40,027
1989	827,629	486,050	529,019	464,136	13.72	33,829
1992	670,695	342,779	373,082	431,752	13.94	30,972
1993	131,544	63,267	68,860	88,993	14.01	6,352
1994	11,673	5,236	5,699	8,309	14.07	591
1995	531,959	220,295	239,770	398,581	14.12	28,228
1996	113,871	42,784	46,566	90,079	14.17	6,357
1999	1,990,316	468,600	510,026	1,878,353	14.30	131,353
2000	987,233	175,925	191,478	993,202	14.33	69,309
2001	4,091,108	464,423	505,480	4,403,850	14.36	306,675
2002	367,709	14,826	16,137	425,114	14.39	29,542
	26,431,681	15,943,774	17,353,280	14,364,742		1,074,426

ARIZONA PUBLIC SERVICE COMPANY

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CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHOLLA UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 48-L2						
PROBABLE RETIREMENT YEAR.. 6-2033						
NET SALVAGE PERCENT.. -20						
1978	120,044,294	73,467,108	87,943,832	56,109,321	20.78	2,700,160
1980	1,897,598	1,105,996	1,323,933	953,185	21.46	44,417
1981	237,906	134,864	161,439	124,048	21.82	5,685
1982	61,146	33,643	40,272	33,103	22.19	1,492
1983	332,150	176,810	211,651	186,929	22.58	8,279
1984	65,215	33,518	40,123	38,135	22.96	1,661
1985	398,166	196,997	235,815	241,984	23.35	10,363
1986	570,152	270,663	323,997	360,185	23.74	15,172
1987	1,714,882	778,488	931,890	1,125,968	24.13	46,663
1988	976,245	422,206	505,402	666,092	24.51	27,176
1989	561,382	230,391	275,790	397,868	24.88	15,991
1991	597,395	217,213	260,015	456,859	25.60	17,846
1992	1,200,361	406,778	486,934	953,499	25.95	36,744
1993	131,544	41,134	49,299	108,554	26.29	4,129
1994	11,669	3,341	3,999	10,004	26.62	376
1995	118,184	30,534	36,551	105,270	26.94	3,908
1999	6,175,050	818,812	980,159	6,429,901	28.10	228,822
2000	283,866	27,490	32,907	307,732	28.36	10,851
2001	144,163	8,563	10,250	162,746	28.60	5,690
2002	5,091,124	104,470	125,056	5,984,293	28.82	207,644
	140,612,492	78,509,069	93,979,314	74,755,676		3,393,069
CHOLLA UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 48-L2						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -20						
1980	91,600,168	52,354,992	60,794,534	49,125,668	22.21	2,211,872
1981	88,342	49,072	56,982	49,028	22.60	2,169
1982	61,283	33,027	38,351	35,189	22.99	1,531
1983	307,043	159,982	185,771	182,681	23.40	7,807
1984	54,259	27,262	31,657	33,454	23.82	1,404

ARIZONA PUBLIC SERVICE COMPANY

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHOLLA UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 48-L2						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -20						
1985	589,413	284,828	330,742	376,554	24.24	15,534
1986	440,024	203,819	236,674	291,355	24.66	11,815
1987	1,127,680	498,931	579,358	773,858	25.08	30,856
1988	602,528	253,857	294,778	428,256	25.49	16,801
1989	361,975	144,471	167,760	266,610	25.90	10,294
1993	175,984	53,302	61,894	149,287	27.46	5,437
1994	11,669	3,226	3,746	10,257	27.83	369
1999	458,424	58,036	67,391	482,718	29.52	16,352
2000	4,173,884	387,670	450,162	4,558,499	29.81	152,918
2001	10,756	613	712	12,195	30.09	405
2002	385,533	7,495	8,703	453,937	30.35	14,957
	100,448,965	54,520,583	63,309,215	57,229,546		2,500,521
CHOLLA COMMON						
INTERIM SURVIVOR CURVE.. IOWA 48-L2						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -20						
1962	720,871	533,127	621,084	243,961	17.79	13,713
1978	9,113,634	5,478,023	6,381,802	4,554,559	21.48	212,037
1980	1,887,095	1,078,588	1,256,536	1,007,978	22.21	45,384
1981	1,629,924	905,390	1,054,764	901,145	22.60	39,874
1982	204,415	110,163	128,338	116,960	22.99	5,087
1983	453,867	236,483	275,499	269,141	23.40	11,502
1984	789,195	396,523	461,942	485,092	23.82	20,365
1985	38,739	18,720	21,808	24,679	24.24	1,018
1986	83,972	38,896	45,313	55,453	24.66	2,249
1987	50,992	22,561	26,283	34,907	25.08	1,392
1988	390,010	164,319	191,429	276,583	25.49	10,851
1989	992,133	395,980	461,310	729,250	25.90	28,156
1990	124,479	46,859	54,590	94,785	26.30	3,604
1991	175,915	62,021	72,253	138,845	26.70	5,200

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHOLLA COMMON INTERIM SURVIVOR CURVE.. IOWA 48-L2 PROBABLE RETIREMENT YEAR.. 6-2035 NET SALVAGE PERCENT.. -20						
1993	32,042	9,705	11,306	27,144	27.46	988
1994	1,330,237	367,784	428,463	1,167,821	27.83	41,963
1996	94,792	20,885	24,331	89,419	28.54	3,133
1998	24,365	3,889	4,531	24,707	29.20	846
2000	3,434,518	318,998	371,627	3,749,795	29.81	125,790
2001	783,936	44,684	52,056	888,667	30.09	29,534
2002	270,920	5,267	6,136	318,968	30.35	10,510
	22,626,051	10,258,865	11,951,401	15,199,859		613,196
FOUR CORNERS UNITS 1-3 INTERIM SURVIVOR CURVE.. IOWA 48-L2 PROBABLE RETIREMENT YEAR.. 6-2016 NET SALVAGE PERCENT.. -20						
1963	6,758,108	6,055,535	5,256,233	2,853,497	10.57	269,962
1964	10,296,561	9,182,885	7,970,787	4,385,086	10.62	412,908
1965	237,400	210,697	182,886	101,994	10.67	9,559
1966	30,135	26,601	23,090	13,072	10.73	1,218
1967	159,048	139,574	121,151	69,707	10.79	6,460
1968	187,736	163,758	142,143	83,140	10.85	7,663
1969	15,218	13,185	11,445	6,817	10.92	624
1970	34,489	29,658	25,743	15,644	11.00	1,422
1972	26,594,905	22,492,907	19,523,948	12,389,938	11.16	1,110,209
1973	2,471,871	2,071,922	1,798,438	1,167,807	11.24	103,897
1974	713,856	592,358	514,169	342,458	11.33	30,226
1975	1,304,528	1,070,600	929,286	636,148	11.43	55,656
1976	1,482,297	1,202,261	1,043,568	735,188	11.53	63,763
1977	3,419,956	2,738,564	2,377,086	1,726,861	11.63	148,483
1978	769,128	607,303	527,142	395,812	11.74	33,715
1979	20,598,276	16,022,163	13,907,312	10,810,619	11.85	912,289
1980	4,929,278	3,771,489	3,273,670	2,641,464	11.96	220,858
1981	1,593,691	1,197,946	1,039,823	872,606	12.07	72,295

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FOUR CORNERS UNITS 1-3 INTERIM SURVIVOR CURVE.. IOWA 48-L2 PROBABLE RETIREMENT YEAR.. 6-2016 NET SALVAGE PERCENT.. -20						
1982	1,985,857	1,463,418	1,270,254	1,112,774	12.19	91,286
1983	2,337,277	1,686,486	1,463,878	1,340,854	12.30	109,013
1984	4,215,644	2,974,053	2,581,492	2,477,281	12.40	199,781
1985	1,295,698	891,388	773,729	781,109	12.51	62,439
1986	5,550,404	3,717,883	3,227,140	3,433,345	12.60	272,488
1987	874,164	568,451	493,418	555,579	12.69	43,781
1988	4,236,229	2,665,774	2,313,904	2,769,571	12.78	216,711
1989	3,165,160	1,922,265	1,668,535	2,129,657	12.85	165,732
1990	9,061,356	5,290,020	4,591,762	6,281,865	12.92	486,212
1991	4,270,649	2,385,072	2,070,253	3,054,526	12.98	235,326
1992	1,381,535	733,264	636,477	1,021,365	13.04	78,326
1993	1,541,140	771,926	670,035	1,179,333	13.09	90,094
1994	663,477	310,905	269,867	526,305	13.14	40,054
1996	4,189,258	1,649,395	1,431,683	3,595,427	13.23	271,763
1997	732,068	256,429	222,582	655,900	13.27	49,427
1998	2,032,166	615,502	534,259	1,904,340	13.30	143,183
1999	22,587,525	5,621,583	4,879,559	22,225,471	13.34	1,666,077
2000	7,367,734	1,388,081	1,204,861	7,636,420	13.37	571,161
2001	3,599,652	434,982	377,566	3,942,016	13.39	294,400
2002	34,456,283	1,484,377	1,288,446	40,059,094	13.42	2,985,029
	197,139,757	104,420,660	90,637,620	145,930,090		11,533,490
FOUR CORNERS COMMON INTERIM SURVIVOR CURVE.. IOWA 48-L2 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -20						
1963	2,134,342	1,610,489	2,303,033	258,177	16.93	15,250
1992	438,444	153,789	219,921	306,212	24.74	12,377
1993	12,365	4,015	5,742	9,096	25.04	363
1994	594,471	176,843	252,889	460,476	25.33	18,179
1996	5,400	1,290	1,845	4,635	25.88	179

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FOUR CORNERS COMMON INTERIM SURVIVOR CURVE.. IOWA 48-L2 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -20						
1999	2,504	348	498	2,507	26.61	94
2002	102,865	2,234	3,194	120,244	27.20	4,421
	3,290,391	1,949,008	2,787,122	1,161,347		50,863
FOUR CORNERS UNITS 4-5 INTERIM SURVIVOR CURVE.. IOWA 48-L2 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -20						
1969	1,388,013	995,705	1,037,348	628,268	17.85	35,197
1970	6,760,776	4,798,799	4,999,499	3,113,432	18.03	172,681
1971	260,556	182,754	190,397	122,270	18.23	6,707
1972	35,207	24,377	25,397	16,851	18.45	913
1973	282,534	192,982	201,053	137,988	18.67	7,391
1974	751,008	505,219	526,348	374,862	18.91	19,823
1975	38,281	25,334	26,394	19,543	19.17	1,019
1976	71,894	46,751	48,706	37,567	19.43	1,933
1977	439,821	280,465	292,195	235,590	19.72	11,947
1978	569,026	355,414	370,278	312,553	20.01	15,620
1979	1,721,144	1,050,655	1,094,596	970,777	20.32	47,774
1980	790,930	470,856	490,549	458,567	20.65	22,207
1981	1,055,469	611,750	637,335	629,228	20.98	29,992
1982	37,150,787	20,904,005	21,778,272	22,802,672	21.33	1,069,042
1983	233,709	127,409	132,738	147,713	21.68	6,813
1984	34,392,552	18,126,251	18,884,344	22,386,718	22.03	1,016,192
1985	887,238	450,468	469,308	595,378	22.39	26,591
1986	4,335,815	2,113,970	2,202,382	3,000,596	22.75	131,894
1987	861,532	402,267	419,091	614,747	23.10	26,612
1988	943,523	420,283	437,860	694,368	23.44	29,623
1989	7,185,027	3,040,129	3,167,276	5,454,756	23.78	229,384
1990	747,180	298,752	311,247	585,369	24.11	24,279
1991	4,090,741	1,537,464	1,601,765	3,307,124	24.43	135,371

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FOUR CORNERS UNITS 4-5 INTERIM SURVIVOR CURVE.. IOWA 48-L2 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -20						
1992	1,000	351	366	834	24.74	34
1993	843,463	273,889	285,344	726,812	25.04	29,026
1994	1,678,748	499,394	520,280	1,494,218	25.33	58,990
1995	546	147	153	502	25.61	20
1996	904,465	215,986	225,019	860,339	25.88	33,243
1997	737,508	152,930	159,326	725,684	26.13	27,772
1998	13,408	2,331	2,428	13,662	26.38	518
1999	175,709	24,395	25,415	185,436	26.61	6,969
2000	630,031	64,490	67,188	688,849	26.82	25,684
2001	118,133	7,457	7,769	133,991	27.02	4,959
2002	1,496,099	32,495	33,854	1,761,465	27.20	64,760
	111,591,873	58,235,923	60,671,520	73,238,729		3,320,980
NAVAJO UNITS 1-3 INTERIM SURVIVOR CURVE.. IOWA 48-L2 PROBABLE RETIREMENT YEAR.. 6-2026 NET SALVAGE PERCENT.. -20						
1974	14,521,356	10,309,001	10,613,768	6,811,859	16.89	403,307
1975	18,453,164	12,903,190	13,284,649	8,859,148	17.10	518,079
1976	22,806,502	15,692,698	16,156,623	11,211,179	17.31	647,671
1977	301,077	203,480	209,496	151,796	17.54	8,654
1978	570,796	378,438	389,626	295,329	17.78	16,610
1979	188,114	122,124	125,734	100,003	18.03	5,546
1980	2,040,145	1,295,084	1,333,371	1,114,803	18.28	60,985
1981	1,783,156	1,103,916	1,136,551	1,003,236	18.55	54,083
1982	507,842	306,046	315,094	294,316	18.82	15,638
1983	1,572,906	920,905	948,130	939,357	19.09	49,207
1984	443,832	251,866	259,312	273,286	19.36	14,116
1985	587,532	322,132	331,655	373,383	19.64	19,011
1986	2,483,250	1,312,050	1,350,838	1,629,062	19.91	81,821
1987	289,940	147,208	151,560	196,368	20.17	9,736

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NAVAJO UNITS 1-3						
INTERIM SURVIVOR CURVE.. IOWA 48-L2						
PROBABLE RETIREMENT YEAR.. 6-2026						
NET SALVAGE PERCENT.. -20						
1988	690,516	335,756	345,682	482,937	20.42	23,650
1989	40,325	18,708	19,261	29,129	20.66	1,410
1990	4,385,568	1,929,825	1,986,877	3,275,805	20.90	156,737
1991	1,454,775	604,546	622,418	1,123,312	21.12	53,187
1992	1,283,648	500,315	515,106	1,025,272	21.33	48,067
1993	594,594	215,338	221,704	491,809	21.54	22,832
1994	1,496,967	499,029	513,782	1,282,578	21.73	59,023
1995	724,344	219,650	226,144	643,069	21.91	29,350
1996	730,614	197,967	203,820	672,917	22.08	30,476
1997	25,597,754	6,054,381	6,233,367	24,483,938	22.24	1,100,896
1998	17,044,540	3,409,590	3,510,388	16,943,060	22.39	756,724
1999	22,050,238	3,548,324	3,653,223	22,807,063	22.53	1,012,298
2000	1,412,959	168,538	173,521	1,522,030	22.66	67,168
2001	4,979,139	369,253	380,169	5,594,798	22.78	245,601
2002	314,650	8,080	8,319	369,261	22.88	16,139
	149,350,243	63,347,438	65,220,188	114,000,103		5,528,022
OCOTILLO UNITS 1-2						
INTERIM SURVIVOR CURVE.. IOWA 48-L2						
PROBABLE RETIREMENT YEAR.. 6-2020						
NET SALVAGE PERCENT.. -20						
1960	9,019,459	7,732,202	9,008,431	1,814,920	12.53	144,846
1961	155,278	132,558	154,437	31,897	12.59	2,534
1963	5,842	4,939	5,754	1,256	12.72	99
1965	1,292	1,080	1,258	292	12.87	23
1966	972	807	940	226	12.95	17
1967	12,120	9,999	11,649	2,895	13.04	222
1969	29,287	23,800	27,728	7,416	13.23	561
1973	1,713,941	1,339,959	1,561,125	495,604	13.69	36,202
1974	41,885	32,349	37,688	12,574	13.83	909
1975	33,471	25,521	29,733	10,432	13.97	747

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OCOTILLO UNITS 1-2 INTERIM SURVIVOR CURVE.. IOWA 48-L2 PROBABLE RETIREMENT YEAR.. 6-2020 NET SALVAGE PERCENT.. -20						
1976	93,157	70,069	81,634	30,154	14.11	2,137
1977	69,896	51,768	60,313	23,562	14.27	1,651
1978	121,661	88,632	103,261	42,732	14.43	2,961
1979	1,938,136	1,387,318	1,616,300	709,463	14.59	48,627
1980	2,935,699	2,060,861	2,401,015	1,121,824	14.76	76,004
1981	215,404	148,086	172,528	85,957	14.93	5,757
1982	323,714	217,497	253,396	135,061	15.11	8,939
1984	8,666	5,530	6,443	3,956	15.45	256
1985	92,232	57,176	66,613	44,065	15.62	2,821
1986	78,895	47,384	55,205	39,469	15.78	2,501
1987	3,020,158	1,752,658	2,041,941	1,582,249	15.93	99,325
1990	30,140	15,447	17,997	18,171	16.34	1,112
1991	256,934	125,117	145,768	162,553	16.46	9,876
1992	20,518	9,437	10,995	13,627	16.57	822
1993	249,520	107,583	125,340	174,084	16.67	10,443
1994	31,221	12,510	14,575	22,890	16.76	1,366
1995	21,126	7,757	9,037	16,314	16.85	968
1996	112,113	37,118	43,244	91,292	16.93	5,392
1997	1,353,674	395,381	460,640	1,163,769	17.00	68,457
1998	345,801	86,436	100,703	314,258	17.07	18,410
1999	344,096	69,865	81,396	331,519	17.14	19,342
2000	559,595	85,282	99,358	572,156	17.19	33,284
2001	677,289	65,020	75,752	736,995	17.24	42,749
2002	239,159	8,064	9,395	277,596	17.29	16,055
	24,152,351	16,215,210	18,891,592	10,091,228		665,415
SAGUARO UNITS 1-2 INTERIM SURVIVOR CURVE.. IOWA 48-L2 PROBABLE RETIREMENT YEAR.. 6-2014 NET SALVAGE PERCENT.. -20						
1953	1	1	1			

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SAGUARO UNITS 1-2						
INTERIM SURVIVOR CURVE.. IOWA 48-L2						
PROBABLE RETIREMENT YEAR.. 6-2014						
NET SALVAGE PERCENT.. -20						
1954	2,133,959	2,031,444	2,371,035	189,716	9.07	20,917
1955	4,018,724	3,816,502	4,454,496	367,973	9.10	40,437
1956	446	422	493	42	9.13	5
1958	10,741	10,121	11,813	1,076	9.18	117
1959	10,963	10,298	12,019	1,137	9.21	123
1960	641	600	700	69	9.24	7
1961	7,479	6,981	8,148	827	9.27	89
1963	14,147	13,107	15,298	1,678	9.34	180
1966	11,963	10,933	12,761	1,595	9.47	168
1967	18,927	17,207	20,083	2,629	9.52	276
1971	2,261,033	2,004,270	2,339,318	373,922	9.74	38,390
1972	27,414	24,120	28,152	4,745	9.80	484
1973	2,615,428	2,281,699	2,663,124	475,390	9.87	48,165
1974	4,632	4,005	4,675	883	9.94	89
1976	133,790	113,363	132,314	28,234	10.09	2,798
1977	689,144	577,227	673,720	153,253	10.17	15,069
1978	438,051	362,233	422,786	102,875	10.26	10,027
1979	60,574	49,428	57,691	14,998	10.34	1,450
1980	8,376	6,735	7,861	2,190	10.42	210
1981	218,080	172,536	201,378	60,318	10.51	5,739
1982	94,876	73,787	86,122	27,729	10.59	2,618
1983	282,239	215,439	251,453	87,234	10.67	8,176
1985	1,546,345	1,130,069	1,318,980	536,634	10.83	49,551
1986	1,322,775	943,350	1,101,047	486,283	10.90	44,613
1989	270,571	176,661	206,193	118,492	11.07	10,704
1990	121,345	76,360	89,125	56,489	11.12	5,080
1992	46,103	26,583	31,027	24,297	11.20	2,169
1994	20,000	10,262	11,977	12,023	11.27	1,067
1995	56,167	26,758	31,231	36,169	11.30	3,201
1996	351,130	153,247	178,865	242,491	11.32	21,421
2001	3,102,325	431,471	503,599	3,219,191	11.44	281,398
2002	4,489,323	225,184	262,827	5,124,361	11.45	447,542
	24,387,712	15,002,403	17,510,312	11,754,943		1,062,280
	800,031,516	418,402,933	442,311,564	517,726,263		29,742,262

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 17.4 3.72

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHOLLA UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 65-R2						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. -20						
1962	4,748,340	4,156,697	5,037,619	660,389	13.29	49,691
1964	568	490	594	88	13.39	7
1966	13,265	11,284	13,675	2,243	13.48	166
1967	1,383	1,167	1,414	246	13.52	18
1969	3,414	2,832	3,432	665	13.60	49
1970	3,114	2,559	3,101	636	13.64	47
1980	2,057,774	1,488,018	1,803,372	665,957	13.94	47,773
1981	314,942	223,773	271,197	106,733	13.96	7,646
1983	161,167	109,948	133,249	60,151	14.01	4,293
1985	57,874	37,655	45,635	23,814	14.05	1,695
1989	48,329	27,722	33,597	24,398	14.13	1,727
1994	578,605	254,748	308,736	385,590	14.20	27,154
1995	17,703	7,180	8,702	12,542	14.22	882
1998	1,329,061	374,795	454,225	1,140,648	14.26	79,989
2001	189,572	21,224	25,722	201,764	14.29	14,119
2002	892,262	35,441	42,952	1,027,762	14.30	71,871
	10,417,373	6,755,533	8,187,222	4,313,626		307,127
CHOLLA UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 65-R2						
PROBABLE RETIREMENT YEAR.. 6-2033						
NET SALVAGE PERCENT.. -20						
1978	25,377,910	13,646,210	17,921,660	12,531,832	27.12	462,088
1983	602,695	282,784	371,382	351,852	27.75	12,679
1984	17,857	8,104	10,643	10,785	27.87	387
1988	71,509	27,640	36,300	49,511	28.28	1,751
1991	16,827	5,521	7,251	12,941	28.55	453
1994	110,349	28,801	37,824	94,595	28.79	3,286
1995	17,703	4,179	5,488	15,756	28.87	546
2001	175,750	9,828	12,907	197,993	29.26	6,767
2002	2,161,289	40,978	53,817	2,539,730	29.32	86,621
	28,551,889	14,054,045	18,457,272	15,804,995		574,578

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHOLLA UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 65-R2						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -20						
1980	23,029,627	11,399,665	14,802,078	12,833,474	28.87	444,526
1982	128,668	60,139	78,088	76,314	29.15	2,618
1983	1,182,069	535,052	694,747	723,736	29.29	24,709
1985	185,638	78,302	101,673	121,093	29.55	4,098
1986	1,413,874	573,467	744,627	952,022	29.67	32,087
1987	2,980,966	1,159,357	1,505,386	2,071,773	29.78	69,569
1988	1,667,007	618,726	803,395	1,197,013	29.90	40,034
1993	513,116	139,342	180,931	434,808	30.40	14,303
1994	766,237	190,701	247,619	671,865	30.49	22,036
1995	17,708	3,982	5,170	16,080	30.58	526
2000	6,803,365	582,912	756,892	7,407,146	30.97	239,172
2002	937,922	16,770	21,775	1,103,731	31.11	35,478
	39,626,197	15,358,415	19,942,381	27,609,055		929,156
CHOLLA COMMON						
INTERIM SURVIVOR CURVE.. IOWA 65-R2						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -20						
1978	232,842	121,320	155,614	123,796	28.56	4,335
1981	370,946	178,588	229,071	216,064	29.01	7,448
1998	27,490	4,005	5,137	27,851	30.82	904
	631,278	303,913	389,822	367,711		12,687
FOUR CORNERS UNITS 1-3						
INTERIM SURVIVOR CURVE.. IOWA 65-R2						
PROBABLE RETIREMENT YEAR.. 6-2016						
NET SALVAGE PERCENT.. -20						
1963	18,336,450	16,243,161	18,057,871	3,945,869	12.50	315,670
1966	3,145	2,729	3,034	740	12.62	59

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FOUR CORNERS UNITS 1-3 INTERIM SURVIVOR CURVE.. IOWA 65-R2 PROBABLE RETIREMENT YEAR.. 6-2016 NET SALVAGE PERCENT.. -20						
1968	77,343	66,082	73,465	19,347	12.69	1,525
1969	11,060	9,369	10,416	2,856	12.73	224
1971	128,769	107,146	119,117	35,406	12.79	2,768
1977	9,291	7,225	8,032	3,117	12.95	241
1978	97,017	74,369	82,678	33,742	12.98	2,600
1979	3,588,036	2,709,972	3,012,734	1,292,909	13.00	99,455
1980	545,643	405,631	450,949	203,823	13.02	15,655
1981	157,102	114,810	127,637	60,885	13.04	4,669
1983	1,090,098	766,295	851,906	456,212	13.08	34,879
1985	159,346	107,004	118,959	72,256	13.12	5,507
1986	129,088	84,501	93,942	60,964	13.13	4,643
1988	65,925	40,623	45,161	33,949	13.17	2,578
1991	430,086	235,550	261,866	254,237	13.21	19,246
1997	119,831	41,356	45,976	97,821	13.28	7,366
1998	700,284	208,657	231,968	608,373	13.29	45,777
2000	4,600,335	858,423	954,327	4,566,075	13.31	343,056
2001	1,826,281	217,839	242,176	1,949,361	13.32	146,348
2002	4,337,796	184,790	205,435	4,999,920	13.33	375,088
	36,412,926	22,485,532	24,997,649	18,697,862		1,427,354
FOUR CORNERS COMMON INTERIM SURVIVOR CURVE.. IOWA 65-R2 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -20						
1963	1,726,164	1,222,538	1,965,225	106,172	23.29	4,559

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FOUR CORNERS UNITS 4-5						
INTERIM SURVIVOR CURVE.. IOWA 65-R2						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -20						
1969	1,940,428	1,269,738	1,592,754	735,760	24.37	30,191
1970	4,817,454	3,105,524	3,895,556	1,885,389	24.53	76,861
1971	30,384	19,277	24,181	12,280	24.69	497
1976	2,236	1,297	1,627	1,056	25.38	42
1977	1,540	875	1,098	750	25.51	29
1978	10	6	8	4	25.63	
1979	5,372	2,917	3,659	2,787	25.75	108
1981	141,365	72,961	91,522	78,116	25.97	3,008
1983	39,270	19,132	23,999	23,125	26.17	884
1984	5,969	2,816	3,532	3,631	26.27	138
1985	233,750	106,562	133,671	146,829	26.36	5,570
1986	5,799	2,547	3,195	3,764	26.45	142
1987	2,975,107	1,254,543	1,573,693	1,996,435	26.54	75,224
1989	50,704	19,435	24,454	36,391	26.70	1,363
1991	640,853	220,325	276,375	492,649	26.85	18,348
1994	57,215	15,695	19,688	48,970	27.06	1,810
1995	141,621	35,264	44,235	125,710	27.12	4,635
1996	685,450	152,170	190,881	631,659	27.18	23,240
1997	277,538	53,654	67,303	265,743	27.24	9,756
1998	26,867	4,369	5,480	26,760	27.30	980
2000	97,215	9,356	11,736	104,922	27.40	3,829
2001	29,349	1,754	2,200	33,019	27.45	1,203
2002	2,282,742	47,116	59,103	2,680,187	27.50	97,461
	14,488,238	6,417,393	8,049,950	9,335,936		355,319
NAVAJO UNITS 1-3						
INTERIM SURVIVOR CURVE.. IOWA 65-R2						
PROBABLE RETIREMENT YEAR.. 6-2026						
NET SALVAGE PERCENT.. -20						
1974	4,253,886	2,787,146	3,265,464	1,839,199	21.35	86,145
1975	5,249,536	3,384,061	3,964,819	2,334,624	21.43	108,942

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NAVAJO UNITS 1-3 INTERIM SURVIVOR CURVE.. IOWA 65-R2 PROBABLE RETIREMENT YEAR.. 6-2026 NET SALVAGE PERCENT.. -20						
1976	6,498,672	4,115,999	4,822,368	2,976,038	21.52	138,292
1977	132,226	82,208	96,316	62,355	21.60	2,887
1978	227,664	138,757	162,570	110,627	21.68	5,103
1979	51,426	30,707	35,977	25,734	21.75	1,183
1980	322,402	188,218	220,519	166,363	21.83	7,621
1982	493,981	274,634	321,765	271,012	21.96	12,341
1983	342,636	185,352	217,161	194,002	22.03	8,806
1984	22,320	11,726	13,738	13,046	22.09	591
1986	315,992	155,392	182,060	197,130	22.21	8,876
1988	377,868	171,854	201,347	252,095	22.32	11,295
1989	40,324	17,531	20,540	27,849	22.37	1,245
1990	141,060	58,365	68,381	100,891	22.42	4,500
1991	120,098	47,054	55,129	88,989	22.46	3,962
1992	663,150	244,066	285,952	509,828	22.51	22,649
1993	1,288,878	442,188	518,075	1,028,579	22.55	45,613
1994	865,158	273,667	320,632	717,558	22.60	31,750
1995	157,606	45,391	53,181	135,946	22.64	6,005
1996	29,682	7,658	8,972	26,646	22.68	1,175
1997	1,481,896	334,849	392,315	1,385,960	22.71	61,029
1998	161,562	30,942	36,252	157,622	22.75	6,928
1999	394,547	61,029	71,502	401,954	22.78	17,645
2001	117,198	8,396	9,837	130,801	22.85	5,724
2002	637,342	15,679	18,370	746,440	22.88	32,624
	24,387,110	13,112,869	15,363,242	13,901,288		632,931
OCOTILLO UNITS 1-2 INTERIM SURVIVOR CURVE.. IOWA 65-R2 PROBABLE RETIREMENT YEAR.. 6-2020 NET SALVAGE PERCENT.. -20						
1960	9,246,108	7,808,893	10,238,105	857,225	15.52	55,234
1962	18,504	15,399	20,189	2,016	15.67	129

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
OCOTILLO UNITS 1-2 INTERIM SURVIVOR CURVE.. IOWA 65-R2 PROBABLE RETIREMENT YEAR.. 6-2020 NET SALVAGE PERCENT.. -20						
1970	599	463	607	112	16.19	7
1971	1,043,214	797,934	1,046,158	205,699	16.25	12,658
1973	3,106	2,319	3,040	687	16.35	42
1981	694,777	455,718	597,484	236,248	16.68	14,164
1982	287,166	184,292	241,622	102,977	16.72	6,159
1985	541,049	321,838	421,956	227,303	16.82	13,514
1987	34,410	19,234	25,217	16,075	16.87	953
1992	706,387	315,331	413,425	434,239	17.00	25,543
1996	436,340	140,536	184,255	339,353	17.09	19,857
1997	2,950	840	1,101	2,439	17.11	143
1998	765,798	186,548	244,580	674,378	17.12	39,391
1999	254,665	50,576	66,309	239,289	17.14	13,961
2001	138,745	13,036	17,091	149,403	17.18	8,696
2002	1,343,783	44,667	58,563	1,553,977	17.19	90,400
	15,517,601	10,357,624	13,579,702	5,041,420		300,851
SAGUARO UNITS 1-2 INTERIM SURVIVOR CURVE.. IOWA 65-R2 PROBABLE RETIREMENT YEAR.. 6-2014 NET SALVAGE PERCENT.. -20						
1955	3,822,099	3,655,455	3,945,585	640,934	10.51	60,983
1959	2,279	2,142	2,312	423	10.66	40
1961	2,664	2,478	2,675	522	10.73	49
1962	35,456	32,812	35,416	7,131	10.76	663
1963	12,012	11,056	11,934	2,480	10.79	230
1967	3,828	3,436	3,709	885	10.91	81
1968	14,140	12,606	13,607	3,361	10.93	308
1970	20,234	17,766	19,176	5,105	10.98	465
1971	5,354,059	4,663,171	5,033,281	1,391,590	11.00	126,508
1972	136	117	126	37	11.02	3
1974	928	786	848	266	11.06	24

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SAGUARO UNITS 1-2						
INTERIM SURVIVOR CURVE.. IOWA 65-R2						
PROBABLE RETIREMENT YEAR.. 6-2014						
NET SALVAGE PERCENT.. -20						
1975	559,911	469,519	506,784	165,109	11.08	14,902
1977	284,980	233,672	252,218	89,758	11.11	8,079
1978	3,316	2,685	2,898	1,081	11.13	97
1981	140,142	108,638	117,261	50,909	11.18	4,554
1982	61,117	46,600	50,299	23,041	11.19	2,059
1986	323,571	227,069	245,091	143,194	11.24	12,740
1987	43,158	29,510	31,852	19,938	11.25	1,772
1990	47,690	29,570	31,917	25,311	11.29	2,242
1993	69,053	37,239	40,195	42,669	11.31	3,773
1994	2,298,293	1,164,407	1,256,825	1,501,127	11.32	132,606
1995	1,617,002	761,026	821,428	1,118,974	11.33	98,762
1996	4,468	1,923	2,076	3,286	11.34	290
1998	1,414,089	474,795	512,478	1,184,429	11.35	104,355
2002	125,073	6,193	6,691	143,397	11.38	12,601
	16,259,698	11,994,677	12,946,682	6,564,957		588,188
	188,018,474	102,062,539	123,679,147	101,743,022		5,132,750
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					19.8	2.73

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHOLLA UNIT 1 INTERIM SURVIVOR CURVE.. IOWA 60-R2.5 PROBABLE RETIREMENT YEAR.. 6-2017 NET SALVAGE PERCENT.. -20						
1962	1,404,779	1,242,049	1,350,425	335,310	12.96	25,873
1963	225,950	198,366	215,675	55,465	13.04	4,253
1964	3,218	2,804	3,049	813	13.12	62
1965	1,683	1,455	1,582	438	13.20	33
1966	5,211	4,470	4,860	1,393	13.27	105
1967	1,432	1,219	1,325	393	13.33	29
1974	460,713	365,438	397,325	155,531	13.71	11,344
1978	15,032	11,296	12,282	5,756	13.87	415
1981	21,818	15,586	16,946	9,236	13.97	661
1983	152,040	104,287	113,387	69,061	14.03	4,922
1984	1,629,565	1,092,330	1,187,642	767,836	14.06	54,611
1985	53,883	35,246	38,321	26,339	14.08	1,871
1986	31,914	20,309	22,081	16,216	14.11	1,149
1987	59,691	36,832	40,100	31,529	14.13	2,231
1988	7,516	4,495	4,887	4,132	14.15	292
1990	67,396	37,324	40,581	40,294	14.19	2,840
1991	26,437	13,984	15,204	16,520	14.21	1,163
2001	588,628	66,044	71,807	634,547	14.35	44,219
	4,756,906	3,253,584	3,537,479	2,170,809		156,073
CHOLLA UNIT 2 INTERIM SURVIVOR CURVE.. IOWA 60-R2.5 PROBABLE RETIREMENT YEAR.. 6-2033 NET SALVAGE PERCENT.. -20						
1978	39,750,065	21,846,636	28,662,246	19,037,832	26.69	713,295
1981	5,872	2,980	3,910	3,136	27.26	115
1983	30,039	14,347	18,823	17,224	27.59	624
1985	590	263	345	363	27.90	13
1986	1,301,479	557,397	731,291	830,484	28.04	29,618
1987	223,461	91,708	120,319	147,834	28.18	5,246
1988	277,444	108,802	142,745	190,188	28.30	6,720

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHOLLA UNIT 2 INTERIM SURVIVOR CURVE.. IOWA 60-R2.5 PROBABLE RETIREMENT YEAR.. 6-2033 NET SALVAGE PERCENT.. -20						
1991	26,433	8,790	11,532	20,188	28.65	705
1995	99,447	23,760	31,173	88,163	29.04	3,036
1999	58,139	7,221	9,474	60,293	29.36	2,054
2000	462,649	42,194	55,357	499,822	29.43	16,983
	42,235,618	22,704,098	29,787,215	20,895,527		778,409
CHOLLA UNIT 3 INTERIM SURVIVOR CURVE.. IOWA 60-R2.5 PROBABLE RETIREMENT YEAR.. 6-2035 NET SALVAGE PERCENT.. -20						
1980	26,570,552	13,455,328	17,309,500	14,575,162	28.46	512,128
1981	5,393	2,653	3,413	3,059	28.67	107
1982	33,272	15,871	20,417	19,509	28.87	676
1983	126,688	58,499	75,256	76,770	29.06	2,642
1985	448,593	192,769	247,986	290,326	29.42	9,868
1986	1,260,075	520,310	669,349	842,741	29.58	28,490
1987	111,014	43,882	56,452	76,765	29.74	2,581
1988	398,681	150,414	193,499	284,918	29.89	9,532
1990	637,276	215,960	277,819	486,912	30.17	16,139
1991	26,440	8,424	10,837	20,891	30.30	689
1995	299,222	68,115	87,626	271,440	30.76	8,824
	29,917,206	14,732,225	18,952,154	16,948,493		591,676
CHOLLA COMMON INTERIM SURVIVOR CURVE.. IOWA 60-R2.5 PROBABLE RETIREMENT YEAR.. 6-2035 NET SALVAGE PERCENT.. -20						
1962	7,471	5,411	7,038	1,927	22.78	85
1978	2,491,361	1,330,686	1,730,891	1,258,742	28.01	44,939

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

CHOLLA COMMON
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5
PROBABLE RETIREMENT YEAR.. 6-2035
NET SALVAGE PERCENT.. -20

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1980	807,017	408,673	531,581	436,839	28.46	15,349
1981	331,945	163,317	212,435	185,899	28.67	6,484
1982	45,894	21,891	28,475	26,598	28.87	921
1984	23,257	10,374	13,494	14,414	29.24	493
1987	3,838	1,517	1,973	2,633	29.74	89
1990	487,071	165,059	214,700	369,785	30.17	12,257
1992	92,682	27,527	35,806	75,412	30.43	2,478
1993	15,378	4,233	5,506	12,948	30.54	424
1999	129,185	15,177	19,742	135,280	31.14	4,344
2001	40,902	2,189	2,847	46,235	31.29	1,478
	4,476,001	2,156,054	2,804,488	2,566,712		89,341

FOUR CORNERS UNITS 1-3
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5
PROBABLE RETIREMENT YEAR.. 6-2016
NET SALVAGE PERCENT.. -20

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1963	1,214,806	1,084,870	847,038	610,729	12.26	49,815
1964	944,133	837,484	653,886	479,074	12.32	38,886
1966	718	628	490	372	12.45	30
1968	257	221	173	135	12.56	11
1969	358	305	238	192	12.61	15
1976	11,488	9,101	7,106	6,680	12.90	518
1978	8,390	6,470	5,052	5,016	12.96	387
1979	5,344	4,059	3,169	3,244	12.99	250
1980	1,968,217	1,470,967	1,148,493	1,213,367	13.02	93,193
1981	524,940	385,579	301,050	328,878	13.05	25,201
1982	1,391,195	1,002,662	782,852	886,582	13.08	67,781
1983	1,453,756	1,026,991	801,848	942,659	13.10	71,959
1984	18,865	13,042	10,183	12,455	13.12	949
1985	137,885	93,039	72,642	92,820	13.15	7,059
1986	4,766	3,134	2,447	3,272	13.17	248

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FOUR CORNERS UNITS 1-3						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2016						
NET SALVAGE PERCENT.. -20						
1987	70,394	44,973	35,114	49,359	13.19	3,742
1988	222,610	137,787	107,580	159,552	13.21	12,078
1989	47,782	28,572	22,308	35,030	13.22	2,650
1990	97,673	56,131	43,826	73,382	13.24	5,542
1991	2,256	1,240	968	1,739	13.26	131
1992	593,211	310,368	242,327	469,526	13.27	35,383
1993	1,143,823	564,683	440,890	931,698	13.29	70,105
1994	450,262	207,913	162,333	377,981	13.30	28,420
1996	391,350	152,110	118,764	350,856	13.32	26,341
1997	1,215,175	420,256	328,125	1,130,085	13.34	84,714
1998	269,736	80,500	62,852	260,831	13.35	19,538
1999	1,157,992	284,588	222,199	1,167,391	13.36	87,380
2000	1,058,531	197,395	154,121	1,116,116	13.37	83,479
2001	1,533,755	183,498	143,270	1,697,236	13.37	126,944
2002	413,614	17,868	13,951	482,386	13.38	36,053
	16,353,282	8,626,434	6,735,295	12,888,643		978,802
FOUR CORNERS COMMON						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -20						
1963	2,592,174	1,905,870	3,017,288	93,321	21.64	4,312
2002	4,545	95	150	5,304	27.72	191
	2,596,719	1,905,965	3,017,438	98,625		4,503

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FOUR CORNERS UNITS 4-5 INTERIM SURVIVOR CURVE.. IOWA 60-R2.5 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -20						
1969	331,641	223,181	256,715	141,254	23.39	6,039
1970	952,784	630,895	725,690	417,651	23.64	17,667
1971	499,067	324,893	373,710	225,170	23.88	9,429
1972	406	260	299	188	24.11	8
1974	1,625	1,002	1,153	797	24.55	32
1976	929	550	633	482	24.94	19
1978	4,998	2,831	3,256	2,742	25.30	108
1979	2,103	1,163	1,338	1,186	25.47	47
1982	1,979,450	1,009,757	1,161,477	1,213,863	25.93	46,813
1983	37,923	18,758	21,576	23,932	26.07	918
1984	3,885,126	1,860,665	2,140,237	2,521,914	26.20	96,256
1985	54,030	24,994	28,749	36,087	26.32	1,371
1986	1,946	867	997	1,338	26.44	51
1987	2,540	1,085	1,248	1,800	26.56	68
1988	925	378	435	675	26.67	25
1989	758,990	295,551	339,959	570,829	26.77	21,323
1991	871	303	349	696	26.96	26
1992	119,397	38,842	44,678	98,598	27.05	3,645
1993	396,799	119,897	137,912	338,247	27.13	12,468
1994	14,191	3,935	4,526	12,503	27.21	460
2000	18,016	1,749	2,012	19,607	27.61	710
2002	119,449	2,494	2,869	140,470	27.72	5,067
	9,183,206	4,564,050	5,249,818	5,770,029		222,550
NAVAJO UNITS 1-3 INTERIM SURVIVOR CURVE.. IOWA 60-R2.5 PROBABLE RETIREMENT YEAR.. 6-2026 NET SALVAGE PERCENT.. -20						
1974	3,712,216	2,469,663	2,979,206	1,475,453	21.05	70,093
1975	4,483,269	2,931,520	3,536,353	1,843,570	21.18	87,043
1976	5,753,279	3,694,986	4,457,338	2,446,597	21.30	114,864

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NAVAJO UNITS 1-3 INTERIM SURVIVOR CURVE.. IOWA 60-R2.5 PROBABLE RETIREMENT YEAR.. 6-2026 NET SALVAGE PERCENT.. -20						
1977	13,487	8,498	10,251	5,933	21.42	277
1978	7,201	4,446	5,363	3,278	21.53	152
1979	5,926	3,583	4,322	2,789	21.63	129
1980	1,968	1,163	1,403	959	21.74	44
1983	250,882	137,192	165,498	135,560	22.01	6,159
1984	28,151	14,952	18,037	15,744	22.09	713
1985	344,308	177,084	213,620	199,550	22.17	9,001
1986	35,616	17,690	21,340	21,399	22.25	962
1987	6,929	3,313	3,997	4,318	22.32	193
1988	53,306	24,467	29,515	34,452	22.39	1,539
1990	26,359	11,004	13,274	18,357	22.51	816
1991	125,310	49,487	59,697	90,675	22.57	4,018
1992	178,776	66,355	80,045	134,486	22.62	5,945
1995	2,587	751	906	2,198	22.77	97
1997	2,032,799	462,502	557,926	1,881,433	22.86	82,302
1998	1,376,411	265,262	319,991	1,331,702	22.90	58,153
1999	1,773,583	275,402	332,223	1,796,077	22.94	78,295
2000	13,831	1,593	1,922	14,675	22.97	639
	20,226,194	10,620,913	12,812,227	11,459,205		521,434
OCOTILLO UNITS 1-2 INTERIM SURVIVOR CURVE.. IOWA 60-R2.5 PROBABLE RETIREMENT YEAR.. 6-2020 NET SALVAGE PERCENT.. -20						
1960	1,774,504	1,522,099	1,951,050	178,355	14.89	11,978
1961	65,192	55,465	71,096	7,134	15.03	475
1963	4,097	3,428	4,394	522	15.28	34
1964	2,088	1,732	2,220	286	15.39	19
1971	3,997	3,088	3,958	838	16.06	52
1974	13,536	10,069	12,907	3,336	16.28	205
1981	23,456	15,495	19,862	8,285	16.68	497

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
OCOTILLO UNITS 1-2						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2020						
NET SALVAGE PERCENT.. -20						
1982	125,540	81,139	104,005	46,643	16.73	2,788
1985	13,186	7,897	10,123	5,700	16.85	338
1987	1,527	858	1,100	732	16.93	43
1990	75,240	37,533	48,110	42,178	17.02	2,478
1991	142,401	67,601	86,652	84,229	17.05	4,940
1998	99,138	24,269	31,108	87,853	17.21	5,105
2002	63,720	2,110	2,705	73,759	17.28	4,268
	2,407,622	1,832,783	2,349,290	539,855		33,220
SAGUARO UNITS 1-2						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2014						
NET SALVAGE PERCENT.. -20						
1954	75,299	72,947	88,885	1,474	10.06	147
1955	845,666	815,797	994,039	20,760	10.13	2,049
1956	2,171	2,084	2,539	66	10.21	6
1957	1,578	1,508	1,837	57	10.28	6
1962	729	679	827	48	10.58	5
1964	118	109	133	9	10.67	1
1970	10,247	9,044	11,020	1,276	10.91	117
1971	873,223	764,419	931,435	116,433	10.94	10,643
1975	25,769	21,708	26,451	4,472	11.06	404
1978	13,566	11,031	13,441	2,838	11.13	255
1979	8,700	6,979	8,504	1,936	11.15	174
1982	17,332	13,271	16,171	4,627	11.20	413
1985	32,441	23,404	28,517	10,412	11.25	926
1987	146,641	100,637	122,625	53,344	11.28	4,729
1989	102,919	66,420	80,932	42,571	11.31	3,764
1990	60,903	37,923	46,209	26,875	11.32	2,374
1992	251,015	143,229	174,523	126,695	11.34	11,172
1994	39,190	19,912	24,263	22,765	11.36	2,004

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SAGUARO UNITS 1-2						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2014						
NET SALVAGE PERCENT.. -20						
1999	62,594	17,449	21,261	53,852	11.40	4,724
2002	84,560	4,170	5,081	96,391	11.42	8,441
	2,654,661	2,132,720	2,598,693	586,901		52,354
	134,807,415	72,528,826	87,844,097	73,924,799		3,428,362

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 21.6 2.54

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHOLLA UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 40-R2						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. -20						
1962	103,140	94,621	74,654	49,114	9.22	5,327
1964	68	61	48	34	9.71	4
1965	675	601	474	336	9.95	34
1966	475	419	331	239	10.18	23
1971	4,486	3,739	2,950	2,433	11.24	216
1972	2,180	1,794	1,415	1,201	11.43	105
1973	2,739	2,226	1,756	1,531	11.61	132
1974	15,571	12,489	9,853	8,832	11.78	750
1975	19,132	15,136	11,942	11,016	11.94	923
1976	15,254	11,894	9,384	8,921	12.10	737
1977	29,405	22,580	17,815	17,471	12.25	1,426
1978	41,171	31,115	24,549	24,856	12.39	2,006
1979	26,739	19,871	15,678	16,409	12.52	1,311
1980	17,688	12,909	10,185	11,041	12.65	873
1981	40,231	28,821	22,739	25,538	12.76	2,001
1982	2,368	1,663	1,312	1,530	12.87	119
1984	62,599	41,984	33,124	41,995	13.08	3,211
1985	170,253	111,325	87,833	116,471	13.17	8,844
1986	108,904	69,263	54,647	76,038	13.26	5,734
1987	171,968	106,152	83,751	122,611	13.34	9,191
1988	4,789	2,858	2,255	3,492	13.42	260
1991	79,578	41,989	33,128	62,366	13.62	4,579
1992	30,869	15,462	12,199	24,844	13.68	1,816
1996	1,040,553	383,589	302,642	946,022	13.89	68,108
1997	13,063	4,279	3,376	12,300	13.93	883
1998	37,703	10,650	8,403	36,841	13.97	2,637
2001	261,197	29,087	22,948	290,488	14.08	20,631
2002	12,391	489	386	14,483	14.11	1,026
	2,315,189	1,077,066	849,777	1,928,453		142,907

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHOLLA UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 40-R2						
PROBABLE RETIREMENT YEAR.. 6-2033						
NET SALVAGE PERCENT.. -20						
1978	2,680,726	1,643,499	2,029,150	1,187,721	19.15	62,022
1981	7,397	4,123	5,090	3,786	20.66	183
1983	7,212	3,742	4,620	4,034	21.62	187
1984	71,489	35,679	44,051	41,736	22.08	1,890
1985	69,432	33,269	41,076	42,242	22.52	1,876
1986	801,518	367,608	453,869	507,953	22.95	22,133
1987	25,025	10,961	13,533	16,497	23.36	706
1988	117,297	48,857	60,321	80,435	23.76	3,385
1990	19,044	7,089	8,752	14,101	24.51	575
1993	15,768	4,732	5,842	13,080	25.51	513
1996	1,014,919	222,876	275,176	942,727	26.38	35,736
2001	8,774	505	623	9,906	27.55	360
2002	7,830	153	189	9,207	27.75	332
	4,846,431	2,383,093	2,942,292	2,873,425		129,898
CHOLLA UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 40-R2						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -20						
1980	2,156,144	1,227,191	1,510,406	1,076,967	20.58	52,331
1981	7,397	4,067	5,006	3,870	21.12	183
1983	175,433	89,534	110,197	100,323	22.17	4,525
1984	123,863	60,733	74,749	73,887	22.68	3,258
1985	10,346	4,863	5,985	6,430	23.17	278
1987	24,592	10,523	12,952	16,558	24.12	686
1988	435,641	177,010	217,860	304,909	24.57	12,410
1993	15,767	4,577	5,633	13,287	26.57	500
1996	1,045,671	220,846	271,814	982,991	27.58	35,641
2001	8,776	482	593	9,938	28.96	343
2002	134,901	2,509	3,088	158,793	29.19	5,440
	4,138,531	1,802,335	2,218,283	2,747,953		115,595

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHOLLA COMMON						
INTERIM SURVIVOR CURVE.. IOWA 40-R2						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -20						
1978	819,188	497,411	567,227	415,799	19.48	21,345
1979	51,856	30,510	34,792	27,435	20.03	1,370
1980	39,642	22,563	25,730	21,840	20.58	1,061
1981	277,926	152,815	174,264	159,247	21.12	7,540
1982	103,137	54,691	62,367	61,397	21.65	2,836
1983	563,360	287,516	327,871	348,161	22.17	15,704
1984	101,024	49,534	56,487	64,742	22.68	2,855
1985	309,053	145,267	165,657	205,207	23.17	8,857
1986	138,523	62,219	70,952	95,276	23.65	4,029
1987	452,905	193,807	221,009	322,477	24.12	13,370
1988	109,043	44,306	50,525	80,327	24.57	3,269
1989	336,303	129,342	147,496	256,068	25.00	10,243
1990	397,203	143,708	163,879	312,765	25.42	12,304
1992	45,783	14,427	16,452	38,488	26.20	1,469
1993	11,473	3,330	3,797	9,971	26.57	375
1994	83,410	22,100	25,202	74,890	26.92	2,782
1996	158,332	33,440	38,134	151,864	27.58	5,506
1997	420,178	76,640	87,397	416,817	27.89	14,945
1998	1,315,246	201,390	229,657	1,348,638	28.17	47,875
2000	239,565	21,417	24,423	263,055	28.71	9,162
2001	58,547	3,218	3,670	66,586	28.96	2,299
2002	1,064,372	19,797	22,575	1,254,671	29.19	42,983
	7,096,069	2,209,448	2,519,563	5,995,721		232,179
FOUR CORNERS UNITS 1-3						
INTERIM SURVIVOR CURVE.. IOWA 40-R2						
PROBABLE RETIREMENT YEAR.. 6-2016						
NET SALVAGE PERCENT.. -20						
1977	4,577	3,592	2,390	3,102	11.58	268
1983	50,000	35,292	23,481	36,519	12.21	2,991
1986	10,083	6,616	4,402	7,698	12.45	618

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FOUR CORNERS UNITS 1-3						
INTERIM SURVIVOR CURVE.. IOWA 40-R2						
PROBABLE RETIREMENT YEAR.. 6-2016						
NET SALVAGE PERCENT.. -20						
1987	23,445	14,942	9,941	18,193	12.52	1,453
1988	471,033	290,929	193,565	371,675	12.58	29,545
1990	82,901	47,512	31,611	67,870	12.70	5,344
1991	142,326	77,983	51,885	118,906	12.76	9,319
1996	380,814	147,375	98,054	358,923	12.98	27,652
1998	31,346	9,340	6,214	31,401	13.05	2,406
1999	180,970	44,367	29,519	187,645	13.09	14,335
2000	147,036	27,278	18,149	158,294	13.12	12,065
2001	159,610	18,904	12,578	178,954	13.15	13,609
2002	2,646,471	114,010	75,855	3,099,910	13.17	235,377
	4,330,612	838,140	557,644	4,639,090		354,982
FOUR CORNERS COMMON						
INTERIM SURVIVOR CURVE.. IOWA 40-R2						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -20						
1963	109,643	94,455	105,296	26,276	11.28	2,329
1967	641	514	573	196	13.22	15
1968	13	10	11	5	13.72	
1969	255	197	220	86	14.23	6
1972	7,042	5,090	5,674	2,776	15.76	176
1973	30,083	21,255	23,695	12,405	16.26	763
1974	23,943	16,512	18,407	10,325	16.77	616
1975	24,485	16,472	18,363	11,019	17.27	638
1976	15,509	10,169	11,336	7,275	17.76	410
1977	186,566	119,059	132,724	91,155	18.25	4,995
1978	37,055	22,993	25,632	18,834	18.73	1,006
1979	493,095	297,218	331,331	260,383	19.20	13,562
1980	228,080	133,454	148,771	124,925	19.65	6,358
1981	131,753	74,672	83,242	74,862	20.10	3,724
1982	218,178	119,623	133,353	128,461	20.53	6,257

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FOUR CORNERS COMMON INTERIM SURVIVOR CURVE.. IOWA 40-R2 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -20						
1983	170,217	90,120	100,464	103,796	20.95	4,954
1984	624,964	318,732	355,314	394,643	21.36	18,476
1985	141,607	69,467	77,440	92,488	21.75	4,252
1986	160,370	75,457	84,118	108,326	22.12	4,897
1987	76,287	34,311	38,249	53,295	22.49	2,370
1988	371,367	159,272	177,552	268,088	22.83	11,743
1989	56,552	23,019	25,661	42,201	23.16	1,822
1990	610,102	234,572	261,495	470,627	23.48	20,044
1991	1,178,136	425,543	474,385	939,378	23.78	39,503
1992	152,094	51,250	57,132	125,381	24.07	5,209
1993	92,185	28,762	32,063	78,559	24.34	3,228
1994	2,086,383	596,372	664,821	1,838,839	24.60	74,750
1995	28,866	7,461	8,317	26,322	24.84	1,060
1996	166,588	38,282	42,676	157,230	25.08	6,269
1997	40,210	8,029	8,951	39,301	25.30	1,553
1998	123,797	20,738	23,118	125,438	25.51	4,917
1999	168,387	22,631	25,229	176,835	25.70	6,881
2000	39,878	3,934	4,385	43,469	25.89	1,679
2001	200,054	12,243	13,648	226,417	26.07	8,685
2002	138,839	2,932	3,269	163,338	26.23	6,227
	8,133,224	3,154,820	3,516,915	6,242,954		269,374
FOUR CORNERS UNITS 4-5 INTERIM SURVIVOR CURVE.. IOWA 40-R2 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -20						
1963	1,238	1,067	1,260	226	11.28	20
1968	320	252	298	86	13.72	6
1969	745	575	679	215	14.23	15
1970	351,515	265,534	313,581	108,237	14.74	7,343
1971	25,649	18,960	22,391	8,388	15.25	550

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FOUR CORNERS UNITS 4-5 INTERIM SURVIVOR CURVE.. IOWA 40-R2 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -20						
1972	8,519	6,157	7,271	2,952	15.76	187
1973	7,039	4,973	5,873	2,574	16.26	158
1974	54,917	37,873	44,726	21,174	16.77	1,263
1975	22,348	15,034	17,754	9,064	17.27	525
1976	47,511	31,152	36,789	20,224	17.76	1,139
1977	36,015	22,983	27,142	16,076	18.25	881
1978	26,933	16,712	19,736	12,584	18.73	672
1979	64,222	38,710	45,714	31,352	19.20	1,633
1980	89,734	52,505	62,006	45,675	19.65	2,324
1981	33,676	19,086	22,540	17,871	20.10	889
1982	43,459	23,828	28,140	24,011	20.53	1,170
1983	131,654	69,703	82,315	75,670	20.95	3,612
1984	328,615	167,594	197,919	196,419	21.36	9,196
1985	202,315	99,248	117,206	125,572	21.75	5,773
1986	170,955	80,438	94,993	110,153	22.12	4,980
1987	62,602	28,156	33,251	41,871	22.49	1,862
1988	237,068	101,674	120,071	164,411	22.83	7,202
1989	32,558	13,252	15,650	23,420	23.16	1,011
1990	6,232	2,396	2,830	4,648	23.48	198
1991	51,515	18,607	21,974	39,844	23.78	1,676
1992	58,711	19,783	23,362	47,091	24.07	1,956
1993	71,187	22,210	26,229	59,195	24.34	2,432
1994	190,028	54,318	64,146	163,888	24.60	6,662
1996	11,745	2,699	3,187	10,907	25.08	435
1998	22,499	3,769	4,451	22,548	25.51	884
1999	21,022	2,825	3,336	21,890	25.70	852
2000	64,955	6,407	7,566	70,380	25.89	2,718
2001	105,415	6,451	7,619	118,879	26.07	4,560
2002	721,424	15,236	17,993	847,716	26.23	32,319
	3,304,340	1,270,167	1,499,998	2,465,211		107,103

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NAVAJO UNITS 1-3						
INTERIM SURVIVOR CURVE.. IOWA 40-R2						
PROBABLE RETIREMENT YEAR.. 6-2026						
NET SALVAGE PERCENT.. -20						
1974	576,505	410,448	447,155	244,651	15.69	15,593
1975	825,683	575,369	626,825	363,995	16.08	22,637
1976	874,179	595,945	649,241	399,774	16.45	24,302
1977	121,651	81,020	88,266	57,715	16.82	3,431
1978	105,586	68,673	74,815	51,888	17.17	3,022
1979	214,004	135,696	147,831	108,974	17.52	6,220
1980	350,828	216,728	236,110	184,884	17.85	10,358
1981	297,688	178,970	194,976	162,250	18.16	8,934
1982	116,109	67,784	73,846	65,485	18.47	3,545
1983	187,980	106,472	115,994	109,582	18.76	5,841
1984	194,651	106,700	116,242	117,339	19.04	6,163
1985	259,944	137,687	150,001	161,932	19.30	8,390
1986	373,496	190,617	207,664	240,531	19.55	12,303
1987	30,906	15,158	16,514	20,573	19.79	1,040
1990	1,182,487	502,888	547,862	871,122	20.44	42,618
1991	136,403	54,769	59,667	104,017	20.64	5,040
1992	131,625	49,596	54,031	103,919	20.82	4,991
1993	171,551	60,132	65,510	140,351	20.99	6,687
1994	137,483	44,413	48,385	116,595	21.15	5,513
1995	115,666	33,950	36,986	101,813	21.31	4,778
1996	44,120	11,600	12,637	40,307	21.45	1,879
1997	3,986,310	915,576	997,458	3,786,114	21.59	175,364
1998	304,842	59,261	64,561	301,249	21.72	13,870
1999	397,589	62,310	67,882	409,225	21.84	18,737
2000	555,475	64,457	70,222	596,348	21.96	27,156
2001	92,062	6,640	7,233	103,241	22.07	4,678
2002	20,427	510	556	23,956	22.17	1,081
	11,805,250	4,753,369	5,178,470	8,987,830		444,171

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

OCOTILLO UNITS 1-2
INTERIM SURVIVOR CURVE.. IOWA 40-R2
PROBABLE RETIREMENT YEAR.. 6-2020
NET SALVAGE PERCENT.. -20

1960	163,799	150,485	133,747	62,812	9.31	6,747
1962	2,034	1,827	1,624	817	9.95	82
1963	96	85	76	39	10.27	4
1966	7,844	6,709	5,963	3,450	11.20	308
1967	3,344	2,823	2,509	1,504	11.50	131
1968	822	685	609	377	11.79	32
1969	2,949	2,424	2,154	1,385	12.08	115
1970	2,586	2,096	1,863	1,240	12.36	100
1971	4,080	3,260	2,897	1,999	12.63	158
1972	2,356	1,855	1,649	1,178	12.89	91
1973	6,146	4,764	4,234	3,141	13.15	239
1974	3,950	3,015	2,680	2,060	13.39	154
1975	1,869	1,403	1,247	996	13.63	73
1976	6,146	4,536	4,031	3,344	13.85	241
1977	64,759	46,937	41,716	35,995	14.07	2,558
1978	7,773	5,530	4,915	4,413	14.27	309
1979	12,760	8,904	7,914	7,398	14.46	512
1980	6,238	4,262	3,788	3,698	14.65	252
1981	46,452	31,060	27,605	28,137	14.82	1,899
1982	22,245	14,527	12,911	13,783	14.99	919
1983	152,131	96,901	86,123	96,434	15.15	6,365
1984	8,256	5,119	4,550	5,357	15.30	350
1985	163,746	98,700	87,722	108,773	15.44	7,045
1986	118,695	69,365	61,650	80,784	15.57	5,188
1987	192	108	96	134	15.69	9
1988	168,425	91,697	81,498	120,612	15.81	7,629
1990	8,646	4,324	3,843	6,532	16.02	408
1991	127,308	60,543	53,809	98,961	16.12	6,139
1993	2,425	1,022	908	2,002	16.30	123
1995	909,880	326,465	290,155	801,701	16.46	48,706
1996	74,482	24,123	21,440	67,938	16.53	4,110
1997	54,733	15,645	13,905	51,775	16.60	3,119
2000	132,221	19,706	17,514	141,151	16.78	8,412

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
OCOTILLO UNITS 1-2 INTERIM SURVIVOR CURVE.. IOWA 40-R2 PROBABLE RETIREMENT YEAR.. 6-2020 NET SALVAGE PERCENT.. -20						
2001	337,622	31,926	28,375	376,771	16.83	22,387
2002	1,084,182	35,908	31,914	1,269,104	16.88	75,184
	3,711,192	1,178,739	1,047,634	3,405,795		210,098
SAGUARO UNITS 1-2 INTERIM SURVIVOR CURVE.. IOWA 40-R2 PROBABLE RETIREMENT YEAR.. 6-2014 NET SALVAGE PERCENT.. -20						
1954	124,955	124,980	104,265	45,681	6.61	6,911
1955	84,213	83,694	69,822	31,234	6.81	4,586
1957	92	90	75	35	7.21	5
1958	4,596	4,477	3,735	1,780	7.40	241
1959	544	526	439	214	7.59	28
1960	1,191	1,144	954	475	7.78	61
1961	2,314	2,207	1,841	936	7.96	118
1966	2,322	2,132	1,779	1,007	8.81	114
1967	122	111	93	53	8.96	6
1968	267	241	201	119	9.11	13
1969	410	367	306	186	9.25	20
1970	2,429	2,155	1,798	1,117	9.38	119
1971	54,268	47,689	39,785	25,337	9.51	2,664
1972	2,171	1,889	1,576	1,029	9.63	107
1973	3,294	2,837	2,367	1,586	9.75	163
1974	6,015	5,126	4,276	2,942	9.86	298
1975	1,093	921	768	544	9.96	55
1976	3,350	2,790	2,328	1,692	10.06	168
1977	23,174	19,068	15,907	11,902	10.15	1,173
1978	65,044	52,811	44,058	33,995	10.24	3,320
1979	13,984	11,198	9,342	7,439	10.32	721
1980	7,462	5,886	4,910	4,044	10.40	389
1981	14,509	11,263	9,396	8,015	10.47	766

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SAGUARO UNITS 1-2						
INTERIM SURVIVOR CURVE.. IOWA 40-R2						
PROBABLE RETIREMENT YEAR.. 6-2014						
NET SALVAGE PERCENT.. -20						
1982	4,297	3,278	2,735	2,421	10.54	230
1983	151,453	113,444	94,641	87,103	10.60	8,217
1984	8,679	6,373	5,317	5,098	10.66	478
1985	37,761	27,120	22,625	22,688	10.72	2,116
1986	58,846	41,275	34,434	36,181	10.77	3,359
1987	14,454	9,874	8,237	9,108	10.82	842
1988	5,001	3,320	2,770	3,231	10.86	298
1990	96,095	59,537	49,669	65,645	10.95	5,995
1991	19,774	11,772	9,821	13,908	10.98	1,267
1992	2,659	1,510	1,260	1,931	11.02	175
1995	558,740	262,764	219,210	451,278	11.11	40,619
1996	30,262	13,011	10,854	25,460	11.14	2,285
1997	34,856	13,427	11,201	30,626	11.17	2,742
2000	354,105	75,297	62,817	362,109	11.24	32,216
2001	1,363,082	186,633	155,699	1,479,999	11.26	131,439
2002	33,141	1,623	1,354	38,415	11.28	3,406
	3,191,024	1,213,860	1,012,665	2,816,563		257,730
YUCCA UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 40-R2						
PROBABLE RETIREMENT YEAR.. 12-2016						
NET SALVAGE PERCENT.. -20						
1959	95,432	90,332	97,873	16,645	8.34	1,996
1963	5,800	5,296	5,738	1,222	9.30	131
1964	866	783	848	191	9.53	20
1965	1,257	1,126	1,220	288	9.76	30
1966	93	82	89	23	9.98	2
1968	309	268	290	81	10.40	8
1969	683	587	636	184	10.60	17
1971	536	450	488	155	10.97	14
1972	1,849	1,535	1,663	556	11.15	50

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
YUCCA UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 40-R2						
PROBABLE RETIREMENT YEAR.. 12-2016						
NET SALVAGE PERCENT.. -20						
1973	3,478	2,852	3,090	1,084	11.32	96
1974	6,999	5,667	6,140	2,259	11.48	197
1975	4,271	3,412	3,697	1,428	11.63	123
1976	3,768	2,968	3,216	1,306	11.78	111
1977	9,906	7,689	8,331	3,556	11.92	298
1978	18,756	14,333	15,530	6,977	12.05	579
1979	15,482	11,641	12,613	5,965	12.17	490
1980	3,504	2,589	2,805	1,400	12.29	114
1981	2,787	2,021	2,190	1,154	12.40	93
1982	12,047	8,567	9,282	5,174	12.50	414
1983	38,024	26,465	28,674	16,955	12.60	1,346
1984	4,766	3,242	3,513	2,206	12.69	174
1985	21,118	14,019	15,189	10,153	12.77	795
1986	113,756	73,495	79,631	56,876	12.85	4,426
1987	46,664	29,258	31,700	24,297	12.93	1,879
1988	2,200	1,336	1,448	1,192	13.00	92
1989	1,017	595	645	575	13.07	44
1990	1,684	948	1,027	994	13.13	76
1991	4,637	2,493	2,701	2,863	13.19	217
1996	31,179	11,789	12,773	24,642	13.43	1,835
	452,868	325,838	353,040	190,401		15,667
	53,324,730	20,206,875	21,696,281	42,293,396		2,279,704

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 18.6 4.28

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 321 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 65-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2024						
NET SALVAGE PERCENT.. 0						
1986	149,653,048	64,141,296	66,715,270	82,937,778	21.12	3,926,978
1987	437,213	180,613	187,861	249,352	21.17	11,779
1988	27,350	10,852	11,287	16,063	21.22	757
1990	2,326,632	842,008	875,798	1,450,834	21.30	68,114
1991	55,626	19,069	19,834	35,792	21.34	1,677
1992	113,422	36,556	38,023	75,399	21.38	3,527
1993	418	126	131	287	21.41	13
1994	36,451	10,148	10,555	25,896	21.44	1,208
1995	120,368	30,525	31,750	88,618	21.48	4,126
1997	104,011	20,761	21,594	82,417	21.53	3,828
1998	131,680	22,320	23,216	108,464	21.56	5,031
1999	840,805	114,938	119,550	721,255	21.59	33,407
2001	93,544	5,949	6,188	87,356	21.63	4,039
2002	7,098,864	156,885	163,181	6,935,683	21.66	320,207
	161,039,432	65,592,046	68,224,238	92,815,194		4,384,691
PALO VERDE UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 65-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2025						
NET SALVAGE PERCENT.. 0						
1986	84,958,776	35,504,272	35,906,605	49,052,171	22.02	2,227,619
1988	343,345	132,772	134,277	209,068	22.12	9,452
1989	127,449	47,131	47,665	79,784	22.17	3,599
1990	2,447,678	861,093	870,851	1,576,827	22.22	70,964
1991	56,178	18,713	18,925	37,253	22.26	1,674
1992	42,543	13,324	13,475	29,068	22.30	1,303
1994	9,603	2,586	2,615	6,988	22.38	312
1995	84,303	20,713	20,948	63,355	22.41	2,827
1996	173	38	38	135	22.45	6
1997	52,488	10,104	10,219	42,269	22.48	1,880
1998	17,439	2,846	2,878	14,561	22.51	647

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 321 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE UNIT 2 INTERIM SURVIVOR CURVE.. IOWA 65-R2.5 PROBABLE RETIREMENT YEAR.. 12-2025 NET SALVAGE PERCENT.. 0						
1999	86,402	11,379	11,508	74,894	22.54	3,323
2000	188,893	18,512	18,722	170,171	22.56	7,543
	88,415,270	36,643,483	37,058,726	51,356,544		2,331,149
PALO VERDE UNIT 3 INTERIM SURVIVOR CURVE.. IOWA 65-R2.5 PROBABLE RETIREMENT YEAR.. 3-2027 NET SALVAGE PERCENT.. 0						
1988	156,500,247	58,640,643	61,090,299	95,409,948	23.25	4,103,654
1989	539,858	193,107	201,174	338,684	23.31	14,530
1990	1,532,499	521,203	542,976	989,523	23.36	42,360
1992	79,634	24,073	25,079	54,555	23.45	2,326
1994	174,636	45,283	47,174	127,462	23.54	5,415
1995	46,564	10,984	11,443	35,121	23.58	1,489
1996	113,380	23,935	24,935	88,445	23.62	3,744
1997	70,281	12,988	13,531	56,750	23.65	2,400
1998	38,093	5,954	6,203	31,890	23.69	1,346
1999	280,002	35,280	36,753	243,249	23.72	10,255
2000	215,883	20,185	21,028	194,855	23.75	8,204
	159,591,077	59,533,635	62,020,595	97,570,482		4,195,723
PALO VERDE WATER RECLAMATION INTERIM SURVIVOR CURVE.. IOWA 65-R2.5 PROBABLE RETIREMENT YEAR.. 3-2027 NET SALVAGE PERCENT.. 0						
1986	112,612,255	45,686,792	48,119,892	64,492,363	23.13	2,788,256
1987	39,514	15,430	16,252	23,262	23.19	1,003
1988	23,430	8,779	9,247	14,183	23.25	610
1989	152,953	54,711	57,625	95,328	23.31	4,090

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 321 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE WATER RECLAMATION						
INTERIM SURVIVOR CURVE.. IOWA 65-R2.5						
PROBABLE RETIREMENT YEAR.. 3-2027						
NET SALVAGE PERCENT.. 0						
1990	242,233	82,383	86,770	155,463	23.36	6,655
1991	1,110,992	357,295	376,323	734,669	23.41	31,383
1992	711,432	215,066	226,520	484,912	23.45	20,679
1993	118,533	33,343	35,119	83,414	23.50	3,550
1994	209,987	54,450	57,350	152,637	23.54	6,484
1995	60,561	14,286	15,047	45,514	23.58	1,930
1996	2,139,083	451,560	475,608	1,663,475	23.62	70,427
1997	4,900,953	905,696	953,929	3,947,024	23.65	166,893
1998	620,987	97,060	102,229	518,758	23.69	21,898
1999	111,434	14,041	14,789	96,645	23.72	4,074
2000	2,207,873	206,436	217,430	1,990,443	23.75	83,808
2001	105,064	6,115	6,440	98,624	23.78	4,147
2002	226,629	4,578	4,822	221,807	23.81	9,316
	125,593,913	48,208,021	50,775,392	74,818,521		3,225,203
PALO VERDE COMMON						
INTERIM SURVIVOR CURVE.. IOWA 65-R2.5						
PROBABLE RETIREMENT YEAR.. 3-2027						
NET SALVAGE PERCENT.. 0						
1986	72,253,263	29,313,149	30,079,922	42,173,341	23.13	1,823,318
1987	33,785	13,193	13,538	20,247	23.19	873
1988	188,104	70,483	72,327	115,777	23.25	4,980
1989	625,898	223,884	229,740	396,158	23.31	16,995
1990	4,146,844	1,410,342	1,447,234	2,699,610	23.36	115,565
1991	9,797,716	3,150,945	3,233,367	6,564,349	23.41	280,408
1992	6,249,889	1,889,341	1,938,762	4,311,127	23.45	183,843
1993	991,829	279,001	286,299	705,530	23.50	30,023
1994	99,578	25,821	26,496	73,082	23.54	3,105
1995	1,334,866	314,895	323,132	1,011,734	23.58	42,906
1996	1,376,971	290,679	298,283	1,078,688	23.62	45,668
1997	441,761	81,637	83,773	357,988	23.65	15,137

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 321 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE COMMON INTERIM SURVIVOR CURVE.. IOWA 65-R2.5 PROBABLE RETIREMENT YEAR.. 3-2027 NET SALVAGE PERCENT.. 0						
2002	586,805	11,853	12,163	574,642	23.81	24,134
	98,127,309	37,075,223	38,045,036	60,082,273		2,586,955
	632,767,001	247,052,408	256,123,987	376,643,014		16,723,721
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					22.5	2.64

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 322 REACTOR PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE UNIT 1 INTERIM SURVIVOR CURVE.. IOWA 70-R1 PROBABLE RETIREMENT YEAR.. 12-2024 NET SALVAGE PERCENT.. -2						
1986	337,017,608	142,040,789	139,384,688	204,373,272	20.59	9,925,851
1987	347,898	141,410	138,766	216,090	20.62	10,480
1988	2,603,683	1,017,952	998,917	1,656,840	20.64	80,273
1989	725,034	271,187	266,116	473,419	20.67	22,904
1990	114,833	40,937	40,171	76,959	20.70	3,718
1991	422,515	142,822	140,151	290,814	20.72	14,035
1992	5,165,616	1,642,852	1,612,131	3,656,797	20.75	176,231
1993	1,074,088	318,920	312,956	782,614	20.77	37,680
1994	176,476	48,457	47,551	132,455	20.79	6,371
1995	3,173,846	794,439	779,584	2,457,739	20.82	118,047
1996	1,820,871	409,346	401,691	1,455,597	20.84	69,846
1997	961,248	189,525	185,981	794,492	20.86	38,087
1998	2,222,601	372,930	365,957	1,901,096	20.88	91,049
1999	1,376,598	186,328	182,844	1,221,286	20.91	58,407
2000	52,413	5,271	5,172	48,289	20.93	2,307
2001	1,995,659	125,798	123,446	1,912,126	20.95	91,271
2002	294,226	6,452	6,331	293,780	20.97	14,010
	359,545,213	147,755,415	144,992,453	221,743,665		10,760,567
PALO VERDE UNIT 2 INTERIM SURVIVOR CURVE.. IOWA 70-R1 PROBABLE RETIREMENT YEAR.. 12-2025 NET SALVAGE PERCENT.. -2						
1986	158,222,101	64,925,806	59,898,557	101,487,986	21.45	4,731,375
1987	4,271,766	1,690,158	1,559,288	2,797,913	21.48	130,257
1988	1,534,235	582,933	537,796	1,027,124	21.51	47,751
1989	47,788	17,372	16,027	32,717	21.54	1,519
1992	1,464,136	451,610	416,642	1,076,777	21.62	49,805
1993	3,473,251	998,692	921,362	2,621,354	21.65	121,079
1994	73,166	19,433	17,928	56,701	21.67	2,617
1995	1,830,784	443,134	408,822	1,458,578	21.70	67,216

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 322 REACTOR PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 12-2025						
NET SALVAGE PERCENT.. -2						
1996	728,366	158,096	145,855	597,078	21.72	27,490
1997	1,293,240	245,749	226,720	1,092,385	21.75	50,225
1998	55,235	8,913	8,223	48,117	21.77	2,210
1999	971,787	126,579	116,778	874,445	21.80	40,112
2000	595,176	57,673	53,207	553,873	21.82	25,384
2001	1,253,560	75,439	69,598	1,209,033	21.85	55,333
2002	547,644	11,507	10,616	547,981	21.87	25,056
	176,362,235	69,813,094	64,407,419	115,482,062		5,377,429
PALO VERDE UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 3-2027						
NET SALVAGE PERCENT.. -2						
1987	4,674	1,789	1,817	2,950	22.55	131
1988	309,856,435	113,842,494	115,599,818	200,453,746	22.58	8,877,491
1989	280,188	98,312	99,830	185,962	22.62	8,221
1991	2,509,333	792,427	804,659	1,754,861	22.68	77,375
1992	1,163,256	345,278	350,608	835,913	22.71	36,808
1993	251,665	69,540	70,613	186,085	22.74	8,183
1994	1,146,768	292,426	296,940	872,763	22.77	38,330
1995	2,309,500	536,391	544,671	1,811,019	22.79	79,466
1996	632,735	131,530	133,560	511,830	22.82	22,429
1997	758,552	138,032	140,163	633,560	22.85	27,727
1998	610,828	94,080	95,532	527,513	22.88	23,056
1999	388,108	48,098	48,840	347,030	22.91	15,148
2000	1,145,667	105,640	107,271	1,061,309	22.93	46,285
2001	1,692,991	97,222	98,723	1,628,128	22.96	70,911
	322,750,700	116,593,259	118,393,045	210,812,669		9,331,561

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 322 REACTOR PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE WATER RECLAMATION INTERIM SURVIVOR CURVE.. IOWA 70-R1 PROBABLE RETIREMENT YEAR.. 3-2027 NET SALVAGE PERCENT.. -2						
2001	118,569	6,809	5,120	115,820	22.96	5,044
2002	4,744	93	70	4,769	22.99	207
	123,313	6,902	5,190	120,589		5,251
PALO VERDE COMMON INTERIM SURVIVOR CURVE.. IOWA 70-R1 PROBABLE RETIREMENT YEAR.. 3-2027 NET SALVAGE PERCENT.. -2						
1986	15,154,553	6,019,207	6,381,612	9,076,032	22.52	403,021
1987	17,897	6,849	7,261	10,994	22.55	488
1988	70,222	25,800	27,353	44,273	22.58	1,961
1989	92,417	32,427	34,379	59,886	22.62	2,647
1991	2,950	932	988	2,021	22.68	89
1992	9,517,452	2,824,970	2,995,058	6,712,743	22.71	295,585
1994	782,562	199,553	211,568	586,645	22.77	25,764
1995	142,435	33,081	35,073	110,211	22.79	4,836
1996	187,203	38,915	41,258	149,689	22.82	6,560
1997	27,499	5,004	5,305	22,744	22.85	995
1998	110,417	17,006	18,030	94,595	22.88	4,134
2000	39,884	3,678	3,899	36,783	22.93	1,604
2001	115,940	6,658	7,059	111,200	22.96	4,843
2002	188,442	3,690	3,912	188,299	22.99	8,190
	26,449,873	9,217,770	9,772,755	17,206,115		760,717
	885,231,334	343,386,440	337,570,862	565,365,100		26,235,525
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					21.5	2.96

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 322.1 REACTOR PLANT EQUIPMENT - STEAM GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE UNIT 1 INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 12-2005 NET SALVAGE PERCENT.. -17						
1986	30,722,375	30,416,810	31,766,117	4,179,062	3.00	1,393,021
PALO VERDE UNIT 2 INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 12-2003 NET SALVAGE PERCENT.. -17						
1986	15,870,053	17,507,731	17,917,124	650,838	1.00	650,838
PALO VERDE UNIT 3 INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 12-2007 NET SALVAGE PERCENT.. -17						
1988	25,413,317	22,109,891	23,597,351	6,136,230	5.00	1,227,246
	72,005,745	70,034,432	73,280,592	10,966,130		3,271,105
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					3.4	4.54

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 323 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE UNIT 1 INTERIM SURVIVOR CURVE.. IOWA 60-S0 PROBABLE RETIREMENT YEAR.. 12-2024 NET SALVAGE PERCENT.. -2						
1986	109,830,205	47,824,245	49,102,998	62,923,811	19.88	3,165,182
1988	119,647	48,401	49,695	72,345	20.02	3,614
1989	408,614	158,504	162,742	254,044	20.09	12,645
1990	341,416	126,448	129,829	218,415	20.15	10,839
1991	528,989	185,935	190,907	348,662	20.22	17,243
1992	557,394	184,776	189,717	378,825	20.29	18,671
1993	966,105	299,471	307,478	677,949	20.36	33,298
1994	116,115	33,328	34,219	84,218	20.43	4,122
1995	317,152	83,203	85,428	238,067	20.51	11,607
1996	485,813	114,566	117,629	377,900	20.58	18,362
1997	796,815	165,151	169,567	643,184	20.66	31,132
1998	144,976	25,582	26,266	121,610	20.74	5,864
1999	1,838,817	263,333	270,375	1,605,218	20.82	77,100
2000	596,040	63,775	65,480	542,481	20.90	25,956
2001	200,619	13,485	13,846	190,785	20.99	9,089
2002	559,361	12,951	13,297	557,251	21.09	26,423
	117,808,078	49,603,154	50,929,473	69,234,765		3,471,147
PALO VERDE UNIT 2 INTERIM SURVIVOR CURVE.. IOWA 60-S0 PROBABLE RETIREMENT YEAR.. 12-2025 NET SALVAGE PERCENT.. -2						
1986	69,976,447	29,720,956	28,954,748	42,421,228	20.67	2,052,309
1988	11,560	4,558	4,440	7,351	20.82	353
1989	152,854	57,749	56,260	99,651	20.89	4,770
1990	54,999	19,831	19,320	36,779	20.96	1,755
1991	661,134	225,909	220,085	454,272	21.04	21,591
1992	409,638	131,909	128,508	289,323	21.11	13,705
1993	787,496	237,038	230,927	572,319	21.19	27,009
1994	1,072,397	298,401	290,709	803,136	21.27	37,759
1995	305,126	77,496	75,498	235,731	21.35	11,041

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 323 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE UNIT 2 INTERIM SURVIVOR CURVE.. IOWA 60-S0 PROBABLE RETIREMENT YEAR.. 12-2025 NET SALVAGE PERCENT.. -2						
1996	122,239	27,904	27,185	97,499	21.43	4,550
1997	845,986	169,561	165,190	697,716	21.51	32,437
1999	1,149,381	158,973	154,875	1,017,494	21.68	46,932
2000	346,144	35,730	34,809	318,258	21.77	14,619
2001	224,777	14,536	14,161	215,112	21.87	9,836
2002	634,046	14,422	14,050	632,677	21.97	28,797
	76,754,224	31,194,973	30,390,765	47,898,546		2,307,463
PALO VERDE UNIT 3 INTERIM SURVIVOR CURVE.. IOWA 60-S0 PROBABLE RETIREMENT YEAR.. 3-2027 NET SALVAGE PERCENT.. -2						
1988	137,174,935	52,441,429	54,402,859	85,515,575	21.80	3,922,733
1989	73,337	26,847	27,851	46,953	21.88	2,146
1991	1,160,978	383,798	398,153	786,045	22.04	35,664
1992	267,875	83,336	86,453	186,780	22.13	8,440
1993	146,174	42,448	44,036	105,061	22.21	4,730
1994	1,326,193	355,900	369,211	983,506	22.30	44,103
1995	387,328	94,857	98,405	296,670	22.38	13,256
1997	231,904	44,730	46,403	190,139	22.56	8,428
1998	435,835	71,173	73,835	370,717	22.66	16,360
2000	1,657,813	163,179	169,282	1,521,687	22.85	66,595
2002	32,716	694	720	32,650	23.07	1,415
	142,895,088	53,708,391	55,717,208	90,035,783		4,123,870

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 323 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE WATER RECLAMATION						
INTERIM SURVIVOR CURVE.. IOWA 60-S0						
PROBABLE RETIREMENT YEAR.. 3-2027						
NET SALVAGE PERCENT.. -2						
1986	121,502	50,106	36,942	86,990	21.64	4,020
1995	96,188	23,557	17,368	80,744	22.38	3,608
2002	17			17	23.07	1
	217,707	73,663	54,310	167,751		7,629
PALO VERDE COMMON						
INTERIM SURVIVOR CURVE.. IOWA 60-S0						
PROBABLE RETIREMENT YEAR.. 3-2027						
NET SALVAGE PERCENT.. -2						
1986	426,809	176,010	69,388-	504,733	21.64	23,324
1988	19,161	7,325	2,888-	22,432	21.80	1,029
1993	245,285	71,229	28,080-	278,271	22.21	12,529
1995	20,547	5,032	1,984-	22,942	22.38	1,025
1997	247,023	47,646	18,783-	270,746	22.56	12,001
2000	265,054	26,089	10,285-	280,640	22.85	12,282
	1,223,879	333,331	131,408-	1,379,764		62,190
	338,898,976	134,913,512	136,960,348	208,716,609		9,972,299
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					20.9	2.94

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 324 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE UNIT 1 INTERIM SURVIVOR CURVE.. IOWA 45-R3 PROBABLE RETIREMENT YEAR.. 12-2024 NET SALVAGE PERCENT.. -2						
1986	111,085,976	50,149,986	50,565,389	62,742,307	19.99	3,138,685
1987	20,587	8,945	9,019	11,980	20.16	594
1988	1,049,796	437,204	440,825	629,967	20.33	30,987
1989	15,973	6,361	6,414	9,878	20.47	483
1990	116,503	44,123	44,488	74,345	20.61	3,607
1991	13,261	4,749	4,788	8,738	20.74	421
1992	857,984	288,710	291,102	584,042	20.86	27,998
1993	667,126	209,244	210,977	469,492	20.97	22,389
1995	100,425	26,448	26,667	75,767	21.17	3,579
1997	790,039	163,505	164,860	640,980	21.33	30,051
1998	82,754	14,501	14,621	69,788	21.41	3,260
1999	73,339	10,383	10,469	64,337	21.47	2,997
2001	621,407	40,692	41,029	592,806	21.59	27,457
	115,495,170	51,404,851	51,830,648	65,974,427		3,292,508
PALO VERDE UNIT 2 INTERIM SURVIVOR CURVE.. IOWA 45-R3 PROBABLE RETIREMENT YEAR.. 12-2025 NET SALVAGE PERCENT.. -2						
1986	8,865,325	3,916,364	3,768,817	5,273,815	20.73	254,405
1987	39,531,366	16,798,142	16,165,282	24,156,711	20.92	1,154,718
1988	35,305	14,376	13,834	22,177	21.10	1,051
1989	903	351	338	583	21.27	27
1991	332,712	116,063	111,690	227,676	21.57	10,555
1992	10,359	3,392	3,264	7,302	21.70	336
1993	202,867	61,808	59,479	147,445	21.83	6,754
1994	38,898	10,927	10,515	29,161	21.94	1,329
1995	307,050	78,454	75,499	237,692	22.05	10,780
1996	58,128	13,293	12,792	46,499	22.14	2,100
1997	466,695	93,444	89,924	386,105	22.23	17,369
1999	269,780	36,818	35,431	239,745	22.39	10,708
	50,119,388	21,143,432	20,346,865	30,774,911		1,470,132

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 324 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 45-R3						
PROBABLE RETIREMENT YEAR.. 3-2027						
NET SALVAGE PERCENT.. -2						
1988	86,650,603	34,337,034	35,633,214	52,750,401	22.04	2,393,394
1989	105,402	39,811	41,314	66,196	22.23	2,978
1990	21,204	7,600	7,887	13,741	22.41	613
1991	856,548	289,799	300,739	572,940	22.57	25,385
1992	221,020	70,067	72,712	152,728	22.73	6,719
1994	201,219	54,615	56,677	148,566	23.00	6,459
1995	9,329	2,297	2,384	7,132	23.13	308
1997	631,690	121,455	126,039	518,285	23.34	22,206
1998	100,102	16,265	16,879	85,225	23.44	3,636
1999	10,979	1,436	1,490	9,709	23.53	413
2000	123,415	11,921	12,371	113,512	23.61	4,808
2002	212,112	4,457	4,625	211,729	23.74	8,919
	89,143,623	34,956,757	36,276,331	54,650,164		2,475,838
PALO VERDE COMMON						
INTERIM SURVIVOR CURVE.. IOWA 45-R3						
PROBABLE RETIREMENT YEAR.. 3-2027						
NET SALVAGE PERCENT.. -2						
1986	13,123,195	5,658,118	5,942,415	7,443,244	21.61	344,435
1987	42,196	17,474	18,352	24,688	21.83	1,131
1988	19,742	7,823	8,216	11,921	22.04	541
1991	130,002	43,984	46,194	86,408	22.57	3,828
1993	4,069,274	1,199,956	1,260,249	2,890,410	22.87	126,384
1995	202,592	49,884	52,390	154,254	23.13	6,669
1997	6,467	1,243	1,305	5,291	23.34	227
1999	324,725	42,462	44,596	286,624	23.53	12,181
	17,918,193	7,020,944	7,373,717	10,902,840		495,396
	272,676,374	114,525,984	115,827,561	162,302,342		7,733,874

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 21.0 2.84

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 325 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE UNIT 1 INTERIM SURVIVOR CURVE.. IOWA 35-R0.5 PROBABLE RETIREMENT YEAR.. 12-2024 NET SALVAGE PERCENT.. -2						
1986	25,471,056	10,296,063	16,014,086	9,966,391	17.46	570,813
1987	35,092	13,659	21,245	14,549	17.60	827
1988	243,376	90,857	141,315	106,929	17.74	6,028
1989	6,991	2,494	3,879	3,252	17.87	182
1990	320,631	108,906	169,388	157,656	17.99	8,764
1991	48,499	15,573	24,222	25,247	18.11	1,394
1992	277,989	83,930	130,541	153,008	18.22	8,398
1993	483,247	136,093	211,674	281,238	18.33	15,343
1994	412,774	107,278	166,856	254,173	18.43	13,791
1995	1,566,928	370,958	576,973	1,021,294	18.53	55,116
1999	705,532	90,099	140,136	579,507	18.87	30,710
2001	99,290	5,864	9,121	92,155	19.02	4,845
	29,671,405	11,321,774	17,609,436	12,655,399		716,211
PALO VERDE UNIT 2 INTERIM SURVIVOR CURVE.. IOWA 35-R0.5 PROBABLE RETIREMENT YEAR.. 12-2025 NET SALVAGE PERCENT.. -2						
1986	13,071,229	5,154,404	8,256,489	5,076,165	18.01	281,853
1988	148,579	53,997	86,494	65,057	18.32	3,551
1989	62,953	21,845	34,992	29,220	18.46	1,583
1990	293,733	96,803	155,062	144,546	18.60	7,771
1991	37,083	11,555	18,509	19,316	18.73	1,031
1992	28,474	8,330	13,343	15,700	18.85	833
1993	137,949	37,569	60,179	80,529	18.97	4,245
1994	5,663,387	1,423,368	2,279,996	3,496,659	19.08	183,263
1995	6,692,661	1,531,870	2,453,799	4,372,715	19.18	227,983
1999	253,358	31,037	49,716	208,709	19.56	10,670
	26,389,406	8,370,778	13,408,579	13,508,616		722,783

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 325 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE UNIT 3 INTERIM SURVIVOR CURVE.. IOWA 35-R0.5 PROBABLE RETIREMENT YEAR.. 3-2027 NET SALVAGE PERCENT.. -2						
1988	22,670,541	7,982,388	13,252,399	9,871,553	19.01	519,282
1989	179,853	60,355	100,202	83,248	19.17	4,343
1990	264,564	84,330	140,005	129,850	19.32	6,721
1991	99,483	29,914	49,663	51,810	19.47	2,661
1992	11,694	3,302	5,482	6,446	19.60	329
1993	559,123	146,797	243,713	326,592	19.73	16,553
1994	3,057,723	738,238	1,225,627	1,893,250	19.86	95,330
1999	52,699	6,160	10,227	43,526	20.40	2,134
2000	388,366	33,592	55,769	340,364	20.50	16,603
	27,284,046	9,085,076	15,083,087	12,746,639		663,956
PALO VERDE WATER RECLAMATION INTERIM SURVIVOR CURVE.. IOWA 35-R0.5 PROBABLE RETIREMENT YEAR.. 3-2027 NET SALVAGE PERCENT.. -2						
1986	13,823	5,293	9,246	4,853	18.67	260
1988	1,700	599	1,046	688	19.01	36
1991	3,428	1,031	1,801	1,696	19.47	87
1992	69,868	19,726	34,459	36,806	19.60	1,878
	88,819	26,649	46,552	44,043		2,261
PALO VERDE COMMON INTERIM SURVIVOR CURVE.. IOWA 35-R0.5 PROBABLE RETIREMENT YEAR.. 3-2027 NET SALVAGE PERCENT.. -2						
1986	14,198,040	5,436,543	7,800,612	6,681,389	18.67	357,868
1987	33,033	12,153	17,438	16,256	18.84	863
1988	3,434,131	1,209,171	1,734,976	1,767,838	19.01	92,995
1989	1,916,089	643,001	922,609	1,031,802	19.17	53,824

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 325 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PALO VERDE COMMON						
INTERIM SURVIVOR CURVE.. IOWA 35-R0.5						
PROBABLE RETIREMENT YEAR.. 3-2027						
NET SALVAGE PERCENT.. -2						
1990	8,638,416	2,753,495	3,950,846	4,860,338	19.32	251,570
1991	2,609,213	784,580	1,125,753	1,535,644	19.47	78,872
1992	2,864,106	808,640	1,160,275	1,761,113	19.60	89,853
1993	2,453,354	644,123	924,218	1,578,203	19.73	79,990
1994	6,215,079	1,500,531	2,153,033	4,186,348	19.86	210,793
1995	1,673,517	367,344	527,083	1,179,904	19.98	59,054
1996	2,111,492	414,591	594,875	1,558,847	20.09	77,593
1997	690,137	118,543	170,091	533,849	20.20	26,428
1998	158,296	22,992	32,990	128,472	20.30	6,329
1999	280,086	32,740	46,977	238,711	20.40	11,702
2000	362,203	31,329	44,952	324,495	20.50	15,829
2002	822,318	15,517	22,265	816,499	20.67	39,502
	48,459,510	14,795,293	21,228,993	28,199,708		1,453,065
	131,893,186	43,599,570	67,376,647	67,154,405		3,558,276

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 18.9 2.70

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 331 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHILDS & IRVING COMBINED INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 12-2004 NET SALVAGE PERCENT.. 0						
1945	74,599	72,092	74,599			
1960	6,421	6,133	6,421			
1998	19,858	13,748	19,858			
	100,878	91,973	100,878			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 0.0 0.00

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 332 RESERVOIRS, DAMS AND WATERWAYS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHILDS & IRVING COMBINED INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 12-2004 NET SALVAGE PERCENT.. 0						
1945	765,472	739,752	874,068	108,596-		
1971	4,101	3,856	4,556	455-		
1990	218,744	188,579	222,819	4,075-		
1991	3,619	3,083	3,643	24-		
	991,936	935,270	1,105,086	113,150-		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 0.0 0.00

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 333 WATER WHEELS, TURBINES AND GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHILDS & IRVING COMBINED						
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 12-2004						
NET SALVAGE PERCENT.. 0						
1945	101,939	98,514	101,939			
1971	55,257	51,958	55,257			
	157,196	150,472	157,196			
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					0.0	0.00

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 334 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHILDS & IRVING COMBINED						
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 12-2004						
NET SALVAGE PERCENT.. 0						
1945	13,191	12,748	13,191			
1971	153,555	144,388	153,555			
1982	9,257	8,434	9,257			
1990	200,918	173,211	200,918			
1991	159,769	136,107	159,769			
1996	90,921	69,527	90,921			
	627,611	544,415	627,611			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 0.0 0.00

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHILDS & IRVING COMBINED INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 12-2004 NET SALVAGE PERCENT.. 0						
1945	4,736	4,577	4,736			
1971	4,192	3,942	4,192			
1972	527	495	527			
1973	2,311	2,164	2,311			
1974	1,589	1,485	1,589			
1975	816	761	816			
1976	563	523	563			
1977	1,565	1,451	1,565			
1978	1,169	1,081	1,169			
1979	179	165	179			
1980	1,221	1,121	1,221			
1981	7,478	6,842	7,478			
1982	327	298	327			
1983	935	848	935			
1984	1,011	912	1,011			
1985	2,506	2,249	2,506			
1986	1,994	1,778	1,994			
1987	1,734	1,536	1,734			
1988	7,200	6,327	7,200			
1990	66,779	57,570	66,779			
1993	11,612	9,593	11,612			
1998	5,574	3,859	5,574			
	126,018	109,577	126,018			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 0.0 0.00

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 336 ROADS, RAILROADS AND BRIDGES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHILDS & IRVING COMBINED						
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 12-2004						
NET SALVAGE PERCENT.. 0						
1945	47,102	45,519	47,102			
1988	342	301	342			
1993	28,694	23,704	28,694			
1995	1,289	1,018	1,289			
	77,427	70,542	77,427			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 0.0 0.00

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
DOUGLAS						
INTERIM SURVIVOR CURVE.. IOWA 80-S1						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. -5						
1972	3,785	2,696	2,851	1,123	13.86	81
1975	777	535	566	250	13.94	18
	4,562	3,231	3,417	1,373		99
OCOTILLO TURBINES 1 - 2						
INTERIM SURVIVOR CURVE.. IOWA 80-S1						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. -5						
1972	9,718	6,922	10,204			
1973	233,393	164,486	245,063			
2001	85,638	8,399	54,652	35,268	14.46	2,439
	328,749	179,807	309,919	35,268		2,439
SAGUARO TURBINES 1 - 2						
INTERIM SURVIVOR CURVE.. IOWA 80-S1						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. -5						
1972	9,836	7,006	6,939	3,389	13.86	245
1973	253,841	178,897	177,188	89,345	13.89	6,432
1974	44,847	31,258	30,959	16,130	13.91	1,160
1987	172,191	93,727	92,832	87,969	14.23	6,182
2001	389,695	38,217	37,852	371,328	14.46	25,680
2002	418,115	14,663	14,523	424,498	14.46	29,357
	1,288,525	363,768	360,293	992,659		69,056

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SOLAR UNIT 1 SURVIVOR CURVE.. 12-SQUARE NET SALVAGE PERCENT.. 0						
1988	640	640	640			
1990	102,091	102,091	102,091			
1991	25,983	24,900	18,490	7,493	0.50	7,493
1994	104,208	73,811	54,809	49,399	3.50	14,114
1995	119,337	74,586	55,385	63,952	4.50	14,212
1998	23,253	8,720	6,475	16,778	7.50	2,237
	375,512	284,748	237,890	137,622		38,056
WEST PHOENIX TURBINES 1 - 2 INTERIM SURVIVOR CURVE.. IOWA 80-S1 PROBABLE RETIREMENT YEAR.. 6-2017 NET SALVAGE PERCENT.. -5						
1972	9,753	6,947	10,100	141	13.86	10
1973	252,701	178,094	258,924	6,412	13.89	462
1974	41,113	28,655	41,660	1,509	13.91	108
1983	3,401	2,054	2,986	585	14.14	41
1987	203,983	111,032	161,426	52,756	14.23	3,707
	510,951	326,782	475,096	61,403		4,328
WEST PHOENIX COMBINED CYCLE 1 - 3 INTERIM SURVIVOR CURVE.. IOWA 80-S1 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -5						
1963	17,431	10,809	18,303			
1971	76,635	43,050	80,467			
1976	2,764,578	1,427,310	2,902,807			
1977	2,943	1,489	3,090			
1978	22,376	11,090	23,495			
1981	22,711	10,471	23,774	73	26.51	3
1983	205,657	89,593	203,414	12,526	26.69	469

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
WEST PHOENIX COMBINED CYCLE 1 - 3 INTERIM SURVIVOR CURVE.. IOWA 80-S1 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -5						
1985	438,587	178,957	406,308	54,208	26.87	2,017
1987	83,179	31,424	71,346	15,992	27.04	591
1989	14,744	5,082	11,538	3,943	27.21	145
1994	30,892	7,597	17,248	15,189	27.60	550
1996	52,610	10,463	23,756	31,485	27.74	1,135
1998	134,795	19,645	44,603	96,932	27.87	3,478
2001	12,598	672	1,526	11,702	28.05	417
2002	2,826,986	51,946	117,939	2,850,396	28.10	101,438
	6,706,722	1,899,598	3,949,614	3,092,446		110,243
YUCCA TURBINES 1 - 4 INTERIM SURVIVOR CURVE.. IOWA 80-S1 PROBABLE RETIREMENT YEAR.. 6-2016 NET SALVAGE PERCENT.. -5						
1971	3,351	2,463	2,204	1,315	12.93	102
1973	9,069	6,535	5,847	3,675	12.98	283
1974	53,788	38,354	34,315	22,162	13.00	1,705
1975	64,575	45,530	40,735	27,069	13.02	2,079
1996	150,787	51,630	46,193	112,133	13.41	8,362
1997	56,340	17,173	15,364	43,793	13.42	3,263
2001	111,767	11,771	10,531	106,824	13.46	7,936
2002	3,074	116	104	3,124	13.47	232
	452,751	173,572	155,293	320,095		23,962
	9,667,772	3,231,506	5,491,522	4,640,866		248,183

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 18.7 2.57

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 342 FUEL HOLDERS, PRODUCTS AND ACCESSORIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
DOUGLAS						
INTERIM SURVIVOR CURVE.. IOWA 70-S1						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. -5						
1972	43,741	31,162	29,409	16,519	13.62	1,213
1973	6,190	4,365	4,120	2,380	13.65	174
1976	6,617	4,502	4,249	2,699	13.76	196
1978	8,724	5,772	5,447	3,713	13.83	268
1992	72,487	32,149	30,341	45,770	14.25	3,212
	137,759	77,950	73,566	71,081		5,063
OCOTILLO TURBINES 1 - 2						
INTERIM SURVIVOR CURVE.. IOWA 70-S1						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. -5						
1972	68,145	48,548	43,233	28,319	13.62	2,079
1973	162,240	114,408	101,882	68,470	13.65	5,016
1974	7,133	4,973	4,429	3,061	13.69	224
1985	74,080	42,758	38,077	39,707	14.05	2,826
1986	33,900	19,043	16,958	18,637	14.08	1,324
1991	351,327	164,158	146,184	222,709	14.22	15,662
1993	23,034	9,619	8,566	15,620	14.28	1,094
	719,859	403,507	359,329	396,523		28,225
SAGUARO TURBINES 1 - 2						
INTERIM SURVIVOR CURVE.. IOWA 70-S1						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. -5						
1972	173,135	123,346	124,944	56,848	13.62	4,174
1973	530	374	379	178	13.65	13
1974	708,283	493,815	500,213	243,484	13.69	17,786
1993	423,029	176,651	178,940	265,240	14.28	18,574
	1,304,977	794,186	804,476	565,750		40,547

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 342 FUEL HOLDERS, PRODUCTS AND ACCESSORIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
WEST PHOENIX TURBINES 1 - 2 INTERIM SURVIVOR CURVE.. IOWA 70-S1 PROBABLE RETIREMENT YEAR.. 6-2017 NET SALVAGE PERCENT.. -5						
1972	171,681	122,310	117,522	62,743	13.62	4,607
1973	3,412	2,406	2,312	1,271	13.65	93
1974	284,024	198,022	190,270	107,955	13.69	7,886
1975	11,989	8,262	7,939	4,649	13.72	339
1977	432,319	290,246	278,884	175,051	13.79	12,694
1985	21	12	12	10	14.05	1
1990	196,631	96,088	92,326	114,137	14.20	8,038
1991	337,456	157,676	151,504	202,825	14.22	14,263
	1,437,533	875,022	840,769	668,641		47,921
WEST PHOENIX COMBINED CYCLE 1 - 3 INTERIM SURVIVOR CURVE.. IOWA 70-S1 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -5						
1974	551,252	297,569	429,424	149,391	24.87	6,007
1976	550,840	286,646	413,661	164,721	25.13	6,555
1977	524	267	385	165	25.26	7
1986	79,628	31,579	45,572	38,037	26.36	1,443
1987	11,263	4,291	6,192	5,634	26.48	213
1990	192,481	63,441	91,552	110,553	26.82	4,122
1993	65,549	17,688	25,526	43,300	27.14	1,595
2000	14,891,456	1,285,282	1,854,800	13,781,229	27.79	495,906
2001	609,575	32,707	47,200	592,854	27.86	21,280
2002	2,391,425	44,194	63,776	2,447,220	27.94	87,588
	19,343,993	2,063,664	2,978,088	17,333,104		624,716

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 342 FUEL HOLDERS, PRODUCTS AND ACCESSORIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
YUCCA TURBINES 1 - 4						
INTERIM SURVIVOR CURVE.. IOWA 70-S1						
PROBABLE RETIREMENT YEAR.. 6-2016						
NET SALVAGE PERCENT.. -5						
1971	118,702	87,246	106,164	18,473	12.71	1,453
1973	128,854	92,881	113,021	22,276	12.77	1,744
1974	2,694,213	1,921,122	2,337,684	491,240	12.81	38,348
1979	21,444	14,334	17,442	5,074	12.96	392
1992	176,590	81,492	99,162	86,258	13.29	6,490
1993	67,217	29,304	35,659	34,919	13.31	2,624
2002	25,197	947	1,152	25,305	13.46	1,880
	3,232,217	2,227,326	2,710,284	683,545		52,931
	26,176,338	6,441,655	7,766,512	19,718,644		799,403
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					24.7	3.05

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 343 PRIME MOVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
DOUGLAS INTERIM SURVIVOR CURVE.. IOWA 70-L1.5 PROBABLE RETIREMENT YEAR.. 6-2017 NET SALVAGE PERCENT.. 0						
1972	1,054,335	714,207	1,062,077	7,742-		
1982	5,455	3,199	4,757	698		
1983	41,659	23,921	35,572	6,087		
	1,101,449	741,327	1,102,406	957-		
OCOTILLO TURBINES 1 - 2 INTERIM SURVIVOR CURVE.. IOWA 70-L1.5 PROBABLE RETIREMENT YEAR.. 6-2017 NET SALVAGE PERCENT.. 0						
1972	2,659,725	1,801,698	2,619,858	39,867	13.40	2,975
1973	3,313,441	2,220,668	3,229,083	84,358	13.45	6,272
1976	60,216	38,930	56,608	3,608	13.59	265
1979	5,051	3,126	4,546	505	13.72	37
1986	97,362	51,894	75,459	21,903	13.99	1,566
1999	407,743	79,469	115,557	292,186	14.33	20,390
2000	93,808	13,874	20,174	73,634	14.35	5,131
2001	41,978	3,942	5,732	36,246	14.37	2,522
	6,679,324	4,213,601	6,127,017	552,307		39,158
SAGUARO TURBINES 1 - 2 INTERIM SURVIVOR CURVE.. IOWA 70-L1.5 PROBABLE RETIREMENT YEAR.. 6-2017 NET SALVAGE PERCENT.. 0						
1972	2,697,385	1,827,209	2,382,986	314,399	13.40	23,463
1973	3,289,440	2,204,583	2,875,145	414,295	13.45	30,803
1976	60,217	38,930	50,771	9,446	13.59	695
1981	2,831	1,692	2,207	624	13.81	45
1982	826,986	485,027	632,556	194,430	13.84	14,048
1992	832,088	350,226	456,753	375,335	14.17	26,488

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 343 PRIME MOVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SAGUARO TURBINES 1 - 2						
INTERIM SURVIVOR CURVE.. IOWA 70-L1.5						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. 0						
2000	158,435	23,433	30,561	127,874	14.35	8,911
2002	235,269	7,905	10,309	224,960	14.39	15,633
	8,102,651	4,939,005	6,441,288	1,661,363		120,086
WEST PHOENIX TURBINES 1 - 2						
INTERIM SURVIVOR CURVE.. IOWA 70-L1.5						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. 0						
1972	2,525,677	1,710,894	2,383,426	142,251	13.40	10,616
1973	3,257,985	2,183,502	3,041,810	216,175	13.45	16,072
1976	101,025	65,313	90,987	10,038	13.59	739
1978	237,433	149,227	207,886	29,547	13.68	2,160
1979	489,711	303,082	422,220	67,491	13.72	4,919
1983	28,515	16,373	22,809	5,706	13.88	411
2001	1,886,893	177,179	246,826	1,640,067	14.37	114,131
2002	275,397	9,253	12,890	262,507	14.39	18,242
	8,802,636	4,614,823	6,428,854	2,373,782		167,290
YUCCA TURBINES 1 - 4						
INTERIM SURVIVOR CURVE.. IOWA 70-L1.5						
PROBABLE RETIREMENT YEAR.. 6-2016						
NET SALVAGE PERCENT.. 0						
1971	2,047,458	1,430,764	2,323,168	275,710-		
1973	2,444,467	1,674,704	2,719,260	274,793-		
1974	3,091,716	2,095,565	3,402,622	310,906-		
1978	326,659	210,499	341,792	15,133-		
1982	10,217	6,162	10,006	211		
2002	67	2	3	64		
	7,920,584	5,417,696	8,796,851	876,267-		
	32,606,644	19,926,452	28,896,416	3,710,228		326,534

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 11.4 1.00

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 344 GENERATORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
DOUGLAS INTERIM SURVIVOR CURVE.. IOWA 37-R3 PROBABLE RETIREMENT YEAR.. 6-2017 NET SALVAGE PERCENT.. 0						
1972	551,765	402,733	546,431	5,334	9.72	549
OCOTILLO TURBINES 1 - 2 INTERIM SURVIVOR CURVE.. IOWA 37-R3 PROBABLE RETIREMENT YEAR.. 6-2017 NET SALVAGE PERCENT.. 0						
1972	289,022	210,957	192,446	96,576	9.72	9,936
1973	438,616	314,839	287,213	151,403	10.09	15,005
1988	940,259	478,310	436,340	503,919	13.49	37,355
1989	1,151,455	563,868	514,390	637,065	13.60	46,843
1993	2,095,383	838,572	764,990	1,330,393	13.94	95,437
1996	126,695	39,491	36,026	90,669	14.13	6,417
2000	423,620	62,653	57,155	366,465	14.29	25,645
2001	936,994	88,265	80,520	856,474	14.32	59,810
	6,402,044	2,596,955	2,369,080	4,032,964		296,448
SAGUARO TURBINES 1 - 2 INTERIM SURVIVOR CURVE.. IOWA 37-R3 PROBABLE RETIREMENT YEAR.. 6-2017 NET SALVAGE PERCENT.. 0						
1972	1,199,388	875,433	920,517	278,871	9.72	28,690
1973	850,430	610,439	641,876	208,554	10.09	20,669
1992	300,243	127,603	134,175	166,068	13.87	11,973
1994	258,349	96,416	101,381	156,968	14.01	11,204
2001	1,576,837	148,538	156,188	1,420,649	14.32	99,207
	4,185,247	1,858,429	1,954,137	2,231,110		171,743

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 344 GENERATORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SOLAR UNIT 1						
SURVIVOR CURVE.. 12-SQUARE						
NET SALVAGE PERCENT.. 0						
1997	893,810	409,633	510,524	383,286	6.50	58,967
1998	3,870,496	1,451,436	1,808,920	2,061,576	7.50	274,877
1999	1,633,145	476,388	593,721	1,039,424	8.50	122,285
2000	436,757	90,976	113,383	323,374	9.50	34,039
2001	98,873	12,359	15,403	83,470	10.50	7,950
	6,933,081	2,440,792	3,041,951	3,891,130		498,118
WEST PHOENIX TURBINES 1 - 2						
INTERIM SURVIVOR CURVE.. IOWA 37-R3						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. 0						
1972	1,184,593	864,634	876,269	308,324	9.72	31,721
1973	790,787	567,627	575,265	215,522	10.09	21,360
1985	253,721	141,830	143,739	109,982	13.11	8,389
1992	1,886,800	801,890	812,680	1,074,120	13.87	77,442
	4,115,901	2,375,981	2,407,953	1,707,948		138,912
WEST PHOENIX COMBINED CYCLE 1 - 3						
INTERIM SURVIVOR CURVE.. IOWA 37-R3						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -2						
1976	1,797,447	1,154,489	1,408,658	424,738	13.69	31,025
1977	2,331	1,452	1,772	606	14.38	42
1978	7,701	4,645	5,668	2,187	15.08	145
1979	2,986	1,742	2,126	920	15.78	58
1982	2,524	1,318	1,608	966	17.88	54
1983	3,159,190	1,583,797	1,932,481	1,289,893	18.57	69,461
1985	131,999	60,628	73,976	60,663	19.90	3,048
1987	346,738	144,440	176,240	177,433	21.15	8,389
1990	76,663	26,845	32,755	45,441	22.84	1,990

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 344 GENERATORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
WEST PHOENIX COMBINED CYCLE 1 - 3						
INTERIM SURVIVOR CURVE.. IOWA 37-R3						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -2						
1996	446,453	90,940	110,961	344,421	25.40	13,560
1998	509,854	75,355	91,945	428,106	26.02	16,453
2000	62,222,903	5,382,032	6,566,925	56,900,436	26.54	2,143,950
2001	8,459,734	452,156	551,702	8,077,227	26.76	301,840
2002	4,753,699	88,248	107,676	4,741,097	26.96	175,857
	81,920,222	9,068,087	11,064,493	72,494,134		2,765,872
YUCCA TURBINES 1 - 4						
INTERIM SURVIVOR CURVE.. IOWA 37-R3						
PROBABLE RETIREMENT YEAR.. 6-2016						
NET SALVAGE PERCENT.. 0						
1971	1,071,486	802,007	927,889	143,597	9.05	15,867
1973	1,074,936	779,974	902,398	172,538	9.73	17,733
1974	1,562,199	1,115,879	1,291,026	271,173	10.04	27,009
1981	368,619	232,267	268,723	99,896	11.74	8,509
1983	344,735	208,117	240,783	103,952	12.06	8,620
1993	42,694	17,786	20,578	22,116	13.04	1,696
2001	819,021	82,148	95,041	723,980	13.36	54,190
2002	112,128	4,037	4,671	107,457	13.38	8,031
	5,395,818	3,242,215	3,751,109	1,644,709		141,655
	109,504,078	21,985,192	25,135,154	86,007,329		4,013,297
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					21.4	3.66

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
DOUGLAS						
INTERIM SURVIVOR CURVE.. IOWA 50-S2						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. 0						
1972	297,620	206,608	263,269	34,351	12.50	2,748
1975	5,529	3,703	4,718	811	12.85	63
1980	5,502	3,412	4,348	1,154	13.38	86
1992	44,626	18,899	24,082	20,544	14.25	1,442
	353,277	232,622	296,417	56,860		4,339
OCOTILLO TURBINES 1 - 2						
INTERIM SURVIVOR CURVE.. IOWA 50-S2						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. 0						
1972	775,819	538,574	655,963	119,856	12.50	9,588
1973	322,270	221,206	269,420	52,850	12.62	4,188
1984	117,478	66,962	81,557	35,921	13.74	2,614
1985	106,389	59,099	71,981	34,408	13.82	2,490
1987	1,529	801	976	553	13.97	40
1990	33,839	15,837	19,289	14,550	14.15	1,028
1994	129,755	48,269	58,789	70,966	14.33	4,952
2002	7,557	252	307	7,250	14.48	501
	1,494,636	951,000	1,158,282	336,354		25,401
SAGUARO TURBINES 1 - 2						
INTERIM SURVIVOR CURVE.. IOWA 50-S2						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. 0						
1972	821,916	570,574	627,394	194,522	12.50	15,562
1973	254,701	174,827	192,237	62,464	12.62	4,950
1982	76	45	49	27	13.57	2
1983	45,868	26,764	29,429	16,439	13.66	1,203
1984	117,272	66,845	73,502	43,770	13.74	3,186

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SAGUARO TURBINES 1 - 2 INTERIM SURVIVOR CURVE.. IOWA 50-S2 PROBABLE RETIREMENT YEAR.. 6-2017 NET SALVAGE PERCENT.. 0						
1985	92,321	51,284	56,391	35,930	13.82	2,600
1987	41,539	21,754	23,921	17,618	13.97	1,261
1988	108,335	54,872	60,337	47,998	14.03	3,421
1990	52,052	24,360	26,786	25,266	14.15	1,786
1992	40,417	17,117	18,822	21,595	14.25	1,515
1994	52,305	19,457	21,394	30,911	14.33	2,157
2002	88,972	2,972	3,268	85,704	14.48	5,919
	1,715,774	1,030,871	1,133,530	582,244		43,562
SOLAR UNIT 1 SURVIVOR CURVE.. 12-SQUARE NET SALVAGE PERCENT.. 0						
2000	103,457	21,550	9,292	94,165	9.50	9,912
2001	66,070	8,259	3,561	62,509	10.50	5,953
	169,527	29,809	12,853	156,674		15,865
WEST PHOENIX TURBINES 1 - 2 INTERIM SURVIVOR CURVE.. IOWA 50-S2 PROBABLE RETIREMENT YEAR.. 6-2017 NET SALVAGE PERCENT.. 0						
1972	699,617	485,674	537,281	162,336	12.50	12,987
1973	380,931	261,471	289,254	91,677	12.62	7,264
1984	116,759	66,553	73,625	43,134	13.74	3,139
1985	104,626	58,120	64,296	40,330	13.82	2,918
1986	1,985	1,072	1,186	799	13.90	57
1990	79,273	37,100	41,042	38,231	14.15	2,702
1993	39,683	15,826	17,508	22,175	14.29	1,552
1994	133,684	49,730	55,014	78,670	14.33	5,490
1996	1,186	369	408	778	14.39	54
	1,557,744	975,915	1,079,614	478,130		36,163

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
WEST PHOENIX COMBINED CYCLE 1 - 3						
INTERIM SURVIVOR CURVE.. IOWA 50-S2						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. 0						
1976	2,303,097	1,240,218	2,303,097			
1977	2,884	1,518	2,884			
1985	31,848	13,156	28,959	2,889	24.34	119
1989	112,405	38,622	85,014	27,391	25.54	1,072
1990	126,211	40,981	90,207	36,004	25.81	1,395
1992	184,125	52,347	115,225	68,900	26.31	2,619
1996	148,416	28,689	63,150	85,266	27.13	3,143
2000	5,026,479	415,690	915,011	4,111,468	27.72	148,321
2002	3,990,180	70,227	154,583	3,835,597	27.93	137,329
	11,925,645	1,901,448	3,758,130	8,167,515		293,998
YUCCA TURBINES 1 - 4						
INTERIM SURVIVOR CURVE.. IOWA 50-S2						
PROBABLE RETIREMENT YEAR.. 6-2016						
NET SALVAGE PERCENT.. 0						
1971	614,123	438,607	591,382	22,741	11.68	1,947
1973	757,805	530,236	714,927	42,878	11.89	3,606
1974	484,841	335,316	452,112	32,729	12.00	2,727
1985	15,463	8,842	11,922	3,541	12.94	274
1986	13,569	7,555	10,187	3,382	13.00	260
1993	5,975	2,485	3,351	2,624	13.33	197
2001	246,938	24,718	33,327	213,611	13.48	15,847
2002	27,812	993	1,339	26,473	13.49	1,962
	2,166,526	1,348,752	1,818,547	347,979		26,820
	19,383,129	6,470,417	9,257,373	10,125,756		446,148

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 22.7 2.30

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
DOUGLAS						
INTERIM SURVIVOR CURVE.. IOWA 70-L1						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. 0						
1972	12,793	8,597	11,481	1,312	13.28	99
1978	238	149	199	39	13.49	3
1981	237	141	188	49	13.61	4
1983	2,045	1,171	1,564	481	13.68	35
1984	1,000	560	748	252	13.72	18
1985	1,267	692	924	343	13.76	25
1986	12,068	6,420	8,574	3,494	13.80	253
1992	10,471	4,400	5,876	4,595	14.03	328
1996	794	246	328	466	14.16	33
	40,913	22,376	29,882	11,031		798
OCOTILLO TURBINES 1 - 2						
INTERIM SURVIVOR CURVE.. IOWA 70-L1						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. 0						
1972	27,636	18,571	27,516	120	13.28	9
1973	214,767	142,884	211,708	3,059	13.31	230
1975	4,765	3,101	4,595	170	13.38	13
1976	29,390	18,895	27,996	1,394	13.41	104
1978	3,414	2,135	3,163	251	13.49	19
1979	826	509	754	72	13.53	5
1980	931	564	836	95	13.57	7
1983	10,251	5,870	8,697	1,554	13.68	114
1985	120,803	66,019	97,819	22,984	13.76	1,670
1987	47,463	24,519	36,330	11,133	13.84	804
1993	47,003	18,627	27,599	19,404	14.06	1,380
1999	45,924	8,937	13,242	32,682	14.24	2,295
	553,173	310,631	460,255	92,918		6,650

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SAGUARO TURBINES 1 - 2						
INTERIM SURVIVOR CURVE.. IOWA 70-L1						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. 0						
1972	33,253	22,346	28,506	4,747	13.28	357
1973	238,419	158,620	202,345	36,074	13.31	2,710
1976	2,105	1,353	1,726	379	13.41	28
1978	2,054	1,285	1,639	415	13.49	31
1983	506	290	370	136	13.68	10
1986	86,316	45,920	58,578	27,738	13.80	2,010
1987	6,340	3,275	4,178	2,162	13.84	156
1991	9,357	4,141	5,283	4,074	13.99	291
1992	24,043	10,103	12,888	11,155	14.03	795
2000	388,513	57,111	72,854	315,659	14.27	22,120
	790,906	304,444	388,367	402,539		28,508
WEST PHOENIX TURBINES 1 - 2						
INTERIM SURVIVOR CURVE.. IOWA 70-L1						
PROBABLE RETIREMENT YEAR.. 6-2017						
NET SALVAGE PERCENT.. 0						
1972	27,545	18,510	23,511	4,034	13.28	304
1973	253,162	168,429	213,936	39,226	13.31	2,947
1975	4,229	2,752	3,496	733	13.38	55
1976	9,477	6,093	7,739	1,738	13.41	130
1977	14,469	9,179	11,659	2,810	13.45	209
1978	4,421	2,765	3,512	909	13.49	67
1979	8,451	5,207	6,614	1,837	13.53	136
1980	673	408	518	155	13.57	11
1981	1,248	743	944	304	13.61	22
1982	4,440	2,594	3,295	1,145	13.65	84
1983	3,403	1,949	2,476	927	13.68	68
1984	2,499	1,399	1,777	722	13.72	53
1985	8,245	4,506	5,723	2,522	13.76	183
1986	102,924	54,756	69,550	33,374	13.80	2,418
1987	5,946	3,072	3,902	2,044	13.84	148

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
WEST PHOENIX TURBINES 1 - 2 INTERIM SURVIVOR CURVE.. IOWA 70-L1 PROBABLE RETIREMENT YEAR.. 6-2017 NET SALVAGE PERCENT.. 0						
1988	3,361	1,681	2,135	1,226	13.88	88
1993	77,442	30,690	38,982	38,460	14.06	2,735
2000	425,496	62,548	79,448	346,048	14.27	24,250
	957,431	377,281	479,217	478,214		33,908
WEST PHOENIX COMBINED CYCLE 1 - 3 INTERIM SURVIVOR CURVE.. IOWA 70-L1 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. 0						
1976	4,807	2,351	4,807			
1977	49,192	23,607	49,192			
1978	11,867	5,581	11,867			
1979	18,683	8,604	18,683			
1981	22,020	9,669	22,020			
1982	8,283	3,541	8,283			
1983	117,544	48,851	117,544			
1984	6,994	2,819	6,994			
1985	146,500	57,091	146,500			
1986	73,454	27,611	72,999	455	25.27	18
1987	26,655	9,630	25,460	1,195	25.40	47
1988	109,370	37,820	99,990	9,380	25.54	367
1989	39,313	12,965	34,277	5,036	25.67	196
1990	5,355	1,676	4,431	924	25.80	36
1991	50,461	14,881	39,343	11,118	25.94	429
1993	1,446,690	371,076	981,068	465,622	26.20	17,772
1996	7,954	1,514	4,003	3,951	26.59	149
1997	29,745	4,926	13,024	16,721	26.71	626
2000	196,926	16,227	42,901	154,025	27.06	5,692
2002	237,064	4,196	11,094	225,970	27.27	8,286
	2,608,877	664,636	1,714,480	894,397		33,618

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
YUCCA TURBINES 1 - 4						
INTERIM SURVIVOR CURVE.. IOWA 70-L1						
PROBABLE RETIREMENT YEAR.. 6-2016						
NET SALVAGE PERCENT.. 0						
1971	18,488	12,818	18,488			
1973	31,311	21,310	31,311			
1974	238,461	160,627	238,461			
1975	791	527	791			
1977	131	85	131			
1978	2,523	1,619	2,523			
1980	1,025	638	1,025			
1982	44,221	26,581	44,221			
1985	9,112	5,136	9,112			
1987	15,888	8,483	15,504	384	12.94	30
1989	37,335	18,645	34,075	3,260	13.01	251
1991	4,636	2,132	3,897	739	13.07	57
1997	23,253	6,727	12,294	10,959	13.24	828
	427,175	265,328	411,833	15,342		1,166
	5,378,475	1,944,696	3,484,034	1,894,441		104,648
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					18.1	1.95

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 352 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -5						
1929	14,612	15,158	14,568	775	0.60	775
1939	2,385	2,359	2,267	237	2.90	82
1942	9,791	9,520	9,149	1,132	3.70	306
1953	24,842	22,145	21,283	4,801	7.55	636
1954	41,569	36,620	35,194	8,453	8.05	1,050
1955	1,534	1,334	1,282	329	8.58	38
1957	58,044	49,074	47,163	13,783	9.74	1,415
1958	35,986	29,956	28,790	8,995	10.36	868
1959	155,159	127,075	122,127	40,790	11.00	3,708
1960	32,361	26,048	25,034	8,945	11.67	766
1961	18,329	14,492	13,928	5,317	12.35	431
1962	238,942	185,457	178,236	72,653	13.04	5,572
1963	198,590	151,218	145,330	63,190	13.74	4,599
1964	3,117	2,326	2,235	1,038	14.46	72
1965	67,857	49,590	47,659	23,591	15.20	1,552
1966	1,908	1,364	1,311	692	15.95	43
1967	25,728	17,986	17,286	9,728	16.71	582
1968	4,381	2,991	2,875	1,725	17.49	99
1969	2,433	1,620	1,557	998	18.29	55
1970	28,371	18,410	17,693	12,097	19.10	633
1971	51,676	32,643	31,372	22,888	19.92	1,149
1972	130,297	80,008	76,893	59,919	20.76	2,886
1973	140,316	83,655	80,398	66,934	21.61	3,097
1974	124,064	71,699	68,907	61,360	22.48	2,730
1975	1,232,121	689,298	662,461	631,266	23.36	27,023
1976	300,526	162,509	156,182	159,370	24.25	6,572
1977	172,008	89,762	86,267	94,341	25.15	3,751
1978	1,004,670	505,088	485,423	569,481	26.06	21,853
1979	326,574	157,872	151,725	191,178	26.98	7,086
1980	1,027,736	476,756	458,194	620,929	27.91	22,248
1981	314,879	139,854	134,409	196,214	28.85	6,801
1982	143,820	61,039	58,663	92,348	29.79	3,100
1983	91,743	37,087	35,643	60,687	30.75	1,974
1984	2,056,981	790,066	759,306	1,400,524	31.71	44,167
1985	187,716	68,315	65,655	131,447	32.67	4,023

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 352 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -5						
1986	6,192,802	2,127,599	2,044,763	4,457,679	33.64	132,511
1987	1,013,595	327,371	314,625	749,650	34.62	21,654
1988	773,594	233,935	224,827	587,447	35.60	16,501
1989	1,637,022	461,346	443,384	1,275,489	36.58	34,868
1990	790,885	206,611	198,567	631,862	37.56	16,823
1991	6,252	1,503	1,444	5,121	38.55	133
1992	66,912	14,698	14,126	56,132	39.54	1,420
1993	59,832	11,899	11,436	51,388	40.53	1,268
1994	416,114	74,102	71,217	365,703	41.52	8,808
1995	45,582	7,160	6,881	40,980	42.52	964
1996	2,251,211	306,818	294,872	2,068,900	43.51	47,550
1997	3,097,968	357,165	343,259	2,909,607	44.51	65,370
1998	247,847	23,369	22,459	237,780	45.51	5,225
1999	277,815	20,419	19,624	272,082	46.50	5,851
2000	122,974	6,456	6,205	122,918	47.50	2,588
2001	2,346,828	73,925	71,047	2,393,122	48.50	49,343
	27,618,299	8,464,770	8,135,201	20,864,015		592,619
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					35.2	2.15

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 352.5 STRUCTURES AND IMPROVEMENTS - SCE 500 KV LINE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 40-SQUARE							
NET SALVAGE PERCENT.. -30							
1971	318,750	40.00	2.50	7,968.75	8.50	.7875	251,016
1972	146	40.00	2.50	3.65	9.50	.7625	111
1973	12,367	40.00	2.50	309.18	10.50	.7375	9,121
1974	17,801	40.00	2.50	445.03	11.50	.7125	12,683
1999	60,661	40.00	2.50	1,516.53	36.50	.0875	5,308
				10,243.14			278,239
NET SALVAGE ADJUSTMENT				3,072.94			83,472
TOTAL	409,725			13,316.08			361,711

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.25

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 353 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 42-R3						
NET SALVAGE PERCENT.. 0						
1929	22,830	22,830	22,830			
1936	3,198	3,117	3,198			
1937	4,788	4,639	4,788			
1938	3,775	3,636	3,775			
1939	58,601	56,087	58,601			
1940	1,302	1,238	1,302			
1945	88,531	81,493	88,531			
1946	8,672	7,931	8,672			
1948	62,397	56,276	62,397			
1949	259,509	232,390	259,509			
1950	224,911	199,946	224,911			
1952	371,456	325,098	371,456			
1953	308,467	267,719	308,467			
1954	1,535,823	1,320,808	1,535,823			
1955	1,488,882	1,268,379	1,488,882			
1956	241,417	203,587	241,417			
1957	615,610	513,419	615,610			
1958	1,052,541	867,820	1,052,541			
1959	1,165,484	949,287	1,165,484			
1960	1,940,121	1,559,469	1,940,121			
1961	192,338	152,447	192,338			
1962	3,149,040	2,459,400	3,149,040			
1963	6,062,058	4,659,298	6,032,311	29,747	9.72	3,060
1964	266,708	201,551	260,945	5,763	10.26	562
1965	553,908	411,221	532,401	21,507	10.82	1,988
1966	506,829	369,276	478,095	28,734	11.40	2,521
1967	388,653	277,615	359,423	29,230	12.00	2,436
1968	481,896	337,086	436,419	45,477	12.62	3,604
1969	1,821,456	1,246,422	1,613,721	207,735	13.26	15,666
1970	2,289,745	1,530,924	1,982,060	307,685	13.92	22,104
1971	5,919,728	3,862,031	5,000,103	919,625	14.60	62,988
1972	2,651,631	1,686,437	2,183,400	468,231	15.29	30,623
1973	4,212,069	2,607,271	3,375,588	836,481	16.00	52,280
1974	3,810,669	2,293,642	2,969,538	841,131	16.72	50,307
1975	13,534,989	7,908,494	10,238,988	3,296,001	17.46	188,774

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 353 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 42-R3						
NET SALVAGE PERCENT.. 0						
1976	4,388,156	2,484,574	3,216,734	1,171,422	18.22	64,293
1977	2,966,492	1,625,934	2,105,068	861,424	18.98	45,386
1978	27,968,778	14,809,468	19,173,557	8,795,221	19.76	445,102
1979	7,842,832	4,003,766	5,183,605	2,659,227	20.56	129,340
1980	19,059,867	9,366,019	12,126,019	6,933,848	21.36	324,618
1981	14,426,831	6,808,022	8,814,226	5,612,605	22.18	253,048
1982	7,393,573	3,342,634	4,327,649	3,065,924	23.01	133,243
1983	4,034,244	1,743,197	2,256,886	1,777,358	23.85	74,522
1984	11,051,702	4,552,196	5,893,648	5,158,054	24.70	208,828
1985	3,012,910	1,178,650	1,525,977	1,486,933	25.57	58,151
1986	38,589,436	14,297,386	18,510,573	20,078,863	26.44	759,412
1987	9,235,173	3,227,693	4,178,837	5,056,336	27.32	185,078
1988	19,545,737	6,412,956	8,302,741	11,242,996	28.22	398,405
1989	11,845,846	3,633,121	4,703,738	7,142,108	29.12	245,265
1990	11,517,106	3,280,072	4,246,651	7,270,455	30.04	242,026
1991	7,395,784	1,944,352	2,517,318	4,878,466	30.96	157,573
1992	2,814,458	677,440	877,070	1,937,388	31.89	60,752
1993	992,039	216,860	280,765	711,274	32.82	21,672
1994	2,768,114	542,550	702,430	2,065,684	33.77	61,169
1995	4,052,181	702,243	909,182	3,142,999	34.72	90,524
1996	46,591,401	7,021,324	9,090,384	37,501,017	35.67	1,051,332
1998	17,354,374	1,818,738	2,354,688	14,999,686	37.60	398,928
1999	15,636,588	1,277,509	1,653,968	13,982,620	38.57	362,526
2000	12,254,988	714,466	925,006	11,329,982	39.55	286,472
2001	25,075,008	877,625	1,136,246	23,938,762	40.53	590,643
2002	45,622,655	533,785	691,082	44,931,573	41.51	1,082,428
	428,736,305	135,040,864	173,966,733	254,769,572		8,167,649

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 31.2 1.91

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 353.5 STATION EQUIPMENT - SCE 500 KV LINE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 40-SQUARE							
NET SALVAGE PERCENT.. -30							
1971	4,774.553	40.00	2.50	119,363.83	8.50	.7875	3,759,960
1972	5,442	40.00	2.50	136.05	9.50	.7625	4,150
1973	4,083	40.00	2.50	102.08	10.50	.7375	3,011
1974	11,636	40.00	2.50	290.90	11.50	.7125	8,291
1975	612,152	40.00	2.50	15,303.80	12.50	.6875	420,855
1985	10,837	40.00	2.50	270.93	22.50	.4375	4,741
1986	26,295	40.00	2.50	657.38	23.50	.4125	10,847
1987	2,553	40.00	2.50	63.83	24.50	.3875	989
1989	62,556	40.00	2.50	1,563.90	26.50	.3375	21,113
1990	64,178	40.00	2.50	1,604.45	27.50	.3125	20,056
1991	23,855	40.00	2.50	596.38	28.50	.2875	6,858
1992	1,997,827	40.00	2.50	49,945.68	29.50	.2625	524,430
1993	62,335	40.00	2.50	1,558.38	30.50	.2375	14,805
1996	48,637	40.00	2.50	1,215.93	33.50	.1625	7,904
1997	28,210	40.00	2.50	705.25	34.50	.1375	3,879
2000	12,133	40.00	2.50	303.33	37.50	.0625	758
				193,682.10			4,812,647
NET SALVAGE ADJUSTMENT				58,104.63			1,443,794
TOTAL	7,747,282			251,786.73			6,256,441

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.25

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 354 TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. -35						
1959	136,120	116,726	114,665	69,097	21.89	3,157
1961	4,712	3,889	3,820	2,541	23.32	109
1962	8,133,425	6,579,290	6,463,108	4,517,016	24.05	187,818
1963	2,685,421	2,127,337	2,089,771	1,535,547	24.79	61,942
1964	1,244,702	965,360	948,313	732,035	25.53	28,674
1966	356,316	264,084	259,421	221,606	27.06	8,189
1968	631,866	445,958	438,083	414,936	28.63	14,493
1969	6,344	4,365	4,288	4,276	29.42	145
1971	522	340	334	371	31.04	12
1973	374,431	230,095	226,032	279,450	32.69	8,548
1974	3,237,617	1,928,389	1,894,336	2,476,447	33.53	73,858
1975	2,156,815	1,243,296	1,221,341	1,690,359	34.38	49,167
1976	2,501,971	1,394,298	1,369,676	2,007,985	35.23	56,996
1977	282,877	152,181	149,494	232,390	36.09	6,439
1978	33,838,801	17,542,034	17,232,263	28,450,118	36.96	769,754
1980	249,816	119,623	117,511	219,741	38.72	5,675
1981	13,364	6,130	6,022	12,019	39.61	303
1982	2,432,549	1,066,624	1,047,789	2,236,152	40.51	55,200
1984	2,570,893	1,022,817	1,004,755	2,465,951	42.32	58,269
1985	398,441	150,234	147,581	390,314	43.24	9,027
1986	8,215,226	2,927,907	2,876,203	8,214,352	44.16	186,013
1988	458,443	144,203	141,657	477,241	46.02	10,370
1989	3,305,471	969,676	952,552	3,509,834	46.96	74,741
1994	102,867	19,192	18,853	120,017	51.71	2,321
1996	8,700,482	1,242,690	1,220,746	10,524,905	53.65	196,177
2001	1,248,957	41,646	40,910	1,645,182	58.52	28,113
2002	176,082	1,949	1,915	235,796	59.51	3,962
	83,464,531	40,710,333	39,991,439	72,685,678		1,899,472

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 38.3 2.28

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 354.5 TOWERS AND FIXTURES - SCE 500 KV LINE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 40-SQUARE							
NET SALVAGE PERCENT.. -30							
1969	13,581,182	40.00	2.50	339,529.55	6.50	.8375	11,374,240
1983	14,902	40.00	2.50	372.55	20.50	.4875	7,265
1984	49,608	40.00	2.50	1,240.20	21.50	.4625	22,944
1985	27,346	40.00	2.50	683.65	22.50	.4375	11,964
1988	79,546	40.00	2.50	1,988.65	25.50	.3625	28,835
				343,814.60			11,445,248
NET SALVAGE ADJUSTMENT				103,144.38			3,433,574
TOTAL	13,752,584			446,958.98			14,878,822

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.25

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 355 POLES AND FIXTURES - WOOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 48-R1.5						
NET SALVAGE PERCENT.. -35						
1946	60,329	61,368	78,449	2,995	11.83	253
1948	144,187	143,517	183,464	11,188	12.61	887
1949	12,037	11,846	15,143	1,107	13.01	85
1952	58,987	55,926	71,493	8,139	14.29	570
1953	172,285	161,158	206,016	26,569	14.74	1,803
1954	55,946	51,608	65,973	9,554	15.20	629
1955	581,615	528,819	676,013	109,167	15.67	6,967
1956	99,312	88,956	113,716	20,355	16.15	1,260
1957	54,309	47,898	61,230	12,087	16.64	726
1958	451,349	391,733	500,770	108,551	17.14	6,333
1959	191,665	163,606	209,145	49,603	17.65	2,810
1960	66,200	55,517	70,970	18,400	18.18	1,012
1961	1,754,296	1,445,136	1,847,383	520,917	18.71	27,842
1962	133,097	107,575	137,518	42,163	19.26	2,189
1963	30,131	23,890	30,540	10,137	19.81	512
1964	66,632	51,759	66,166	23,787	20.38	1,167
1965	690,274	524,922	671,031	260,839	20.96	12,445
1966	110,021	81,869	104,657	43,871	21.54	2,037
1967	84,908	61,749	78,937	35,689	22.14	1,612
1968	245,297	174,252	222,754	108,397	22.74	4,767
1969	369,647	256,149	327,447	171,576	23.36	7,345
1970	206,840	139,729	178,622	100,612	23.98	4,196
1971	170,726	112,267	143,516	86,964	24.62	3,532
1972	541,168	346,074	442,402	288,175	25.26	11,408
1973	164,843	102,412	130,918	91,620	25.91	3,536
1974	133,662	80,568	102,994	77,450	26.57	2,915
1975	434,209	253,524	324,091	262,091	27.24	9,622
1976	518,432	292,901	374,429	325,454	27.91	11,661
1977	969,302	529,181	676,476	632,082	28.59	22,108
1978	961,029	505,982	646,820	650,569	29.28	22,219
1979	1,003,363	508,494	650,031	704,509	29.98	23,499
1980	1,208,105	588,118	751,818	879,124	30.69	28,645
1981	1,058,954	494,351	631,951	797,637	31.40	25,402
1982	2,037,584	910,494	1,163,925	1,586,813	32.11	49,419
1983	646,717	275,715	352,459	520,609	32.84	15,853

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 355 POLES AND FIXTURES - WOOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 48-R1.5						
NET SALVAGE PERCENT.. -35						
1984	2,620,356	1,063,367	1,359,350	2,178,131	33.57	64,883
1985	1,793,032	690,837	883,128	1,537,465	34.30	44,824
1986	7,555,234	2,753,883	3,520,413	6,679,153	35.04	190,615
1987	5,321,740	1,827,698	2,336,429	4,847,920	35.79	135,455
1988	4,069,787	1,311,469	1,676,510	3,817,702	36.54	104,480
1989	6,586,670	1,982,028	2,533,715	6,358,290	37.30	170,464
1990	4,297,988	1,201,653	1,536,127	4,266,157	38.06	112,090
1991	5,131,132	1,323,062	1,691,330	5,235,698	38.83	134,836
1992	2,117,466	500,251	639,493	2,219,086	39.60	56,038
1993	2,240,722	480,063	613,686	2,411,289	40.38	59,715
1994	2,627,836	505,530	646,242	2,901,337	41.16	70,489
1995	7,231,893	1,230,145	1,572,550	8,190,506	41.95	195,244
1996	3,054,164	451,894	577,676	3,545,445	42.74	82,954
1997	3,032,561	381,147	487,237	3,606,720	43.53	82,856
1998	3,169,350	327,315	418,422	3,860,201	44.33	87,079
1999	3,508,799	282,313	360,900	4,375,979	45.14	96,942
2000	3,187,136	183,722	234,860	4,067,774	45.95	88,526
2001	2,522,226	87,168	111,431	3,293,574	46.77	70,421
2002	5,571,389	63,932	81,727	7,439,648	47.59	156,328
	91,126,939	26,276,545	33,590,493	89,430,875		2,321,504
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					38.5	2.55

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 355.1 POLES AND FIXTURES - STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. -15						
1953	595,686	511,382	606,038	79,001	13.94	5,667
1958	1,862,217	1,481,096	1,755,243	386,307	16.96	22,778
1961	1,357,829	1,023,722	1,213,211	348,292	18.94	18,389
1964	151,112	107,308	127,170	46,609	21.04	2,215
1965	549,324	381,687	452,336	179,387	21.77	8,240
1968	208,890	135,366	160,422	79,802	24.01	3,324
1969	715,441	452,187	535,886	286,871	24.77	11,581
1970	711,756	438,317	519,448	299,071	25.55	11,705
1971	1,735	1,040	1,233	762	26.34	29
1972	186,930	108,882	129,036	85,934	27.14	3,166
1973	851,806	481,952	571,160	408,417	27.94	14,618
1974	51,022	27,994	33,176	25,499	28.76	887
1976	49,632	25,508	30,229	26,848	30.42	883
1977	444,813	220,778	261,644	249,891	31.26	7,994
1978	9,412	4,503	5,336	5,488	32.12	171
1980	681,477	301,489	357,294	426,405	33.84	12,601
1981	78,212	33,162	39,300	50,644	34.72	1,459
1982	4,607,251	1,868,724	2,214,621	3,083,718	35.60	86,621
1983	57,585	22,284	26,409	39,814	36.49	1,091
1984	238,766	87,921	104,195	170,386	37.39	4,557
1985	157,774	55,085	65,281	116,159	38.30	3,033
1986	10,260,930	3,387,800	4,014,874	7,785,196	39.21	198,551
1987	4,080,364	1,268,830	1,503,688	3,188,731	40.13	79,460
1988	5,654,228	1,648,349	1,953,455	4,548,907	41.06	110,787
1989	6,369,486	1,732,341	2,052,993	5,271,916	41.99	125,552
1990	1,182,484	298,489	353,739	1,006,118	42.93	23,436
1991	447,684	104,203	123,491	391,346	43.87	8,921
1992	2,959,482	630,651	747,383	2,656,021	44.81	59,273
1993	337,295	65,088	77,136	310,753	45.77	6,789
1994	234,244	40,542	48,046	221,335	46.72	4,737
1995	22,678	3,466	4,108	21,972	47.69	461
1996	2,557,082	339,644	402,511	2,538,133	48.65	52,171
1997	1,177,666	132,452	156,968	1,197,348	49.62	24,130
1998	1,846,365	170,290	201,810	1,921,510	50.59	37,982
1999	5,933,176	425,765	504,573	6,318,579	51.57	122,524

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 355.1 POLES AND FIXTURES - STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. -15						
2000	3,659,502	188,117	222,937	3,985,490	52.54	75,856
2001	17,540,202	542,606	643,041	19,528,191	53.52	364,877
2002	5,236,350	53,594	63,514	5,958,289	54.51	109,306
	83,067,888	18,802,614	22,282,935	73,245,140		1,625,822

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 45.1 1.96

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 355.5 POLES AND FIXTURES - SCE 500 KV LINE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 40-SQUARE							
NET SALVAGE PERCENT.. -30							
1983	930,308	40.00	2.50	23,257.70	20.50	.4875	453,525
				23,257.70			453,525
NET SALVAGE ADJUSTMENT				6,977.31			136,058
TOTAL	930,308			30,235.01			589,583

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.25

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. -35						
1946	125,388	137,230	121,006	48,268	10.41	4,637
1948	88,268	94,614	83,428	35,734	11.33	3,154
1949	19,958	21,153	18,652	8,291	11.82	701
1951	40,962	42,381	37,370	17,929	12.85	1,395
1952	129,401	132,154	116,530	58,161	13.39	4,344
1953	796,068	802,257	707,410	367,282	13.94	26,347
1954	60,400	60,030	52,933	28,607	14.51	1,972
1955	815,052	798,282	703,905	396,415	15.10	26,253
1956	145,887	140,699	124,065	72,882	15.71	4,639
1957	93,857	89,113	78,578	48,129	16.32	2,949
1958	2,775,535	2,591,406	2,285,036	1,461,936	16.96	86,199
1959	351,418	322,507	284,378	190,036	17.61	10,791
1960	114,717	103,421	91,194	63,674	18.27	3,485
1961	2,736,348	2,421,832	2,135,510	1,558,560	18.94	82,289
1962	11,954,163	10,378,425	9,151,432	6,986,688	19.63	355,919
1963	4,067,080	3,461,248	3,052,041	2,438,517	20.33	119,947
1964	1,599,053	1,333,011	1,175,415	983,307	21.04	46,735
1965	703,539	573,856	506,012	443,766	21.77	20,384
1966	183,920	146,716	129,370	118,922	22.50	5,285
1967	173,949	135,568	119,540	115,291	23.25	4,959
1968	1,164,432	885,813	781,087	790,896	24.01	32,940
1969	1,055,256	782,958	690,392	734,204	24.77	29,641
1970	864,614	625,051	551,154	616,075	25.55	24,113
1971	446,552	314,143	277,003	325,842	26.34	12,371
1972	1,304,564	892,028	786,568	974,593	27.14	35,910
1973	1,242,178	825,055	727,513	949,427	27.94	33,981
1974	3,270,899	2,106,737	1,857,667	2,558,047	28.76	88,945
1975	477,370	297,736	262,536	381,914	29.59	12,907
1976	5,499,116	3,317,699	2,925,463	4,498,344	30.42	147,875
1977	1,914,433	1,115,464	983,588	1,600,897	31.26	51,212
1978	27,073,883	15,204,693	13,407,113	23,142,629	32.12	720,505
1979	797,589	431,236	380,253	696,492	32.97	21,125
1980	1,566,356	813,479	717,305	1,397,276	33.84	41,291
1981	1,482,558	737,936	650,693	1,350,760	34.72	38,904
1982	8,839,622	4,208,942	3,711,338	8,222,152	35.60	230,959

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. -35						
1983	1,105,365	502,140	442,774	1,049,469	36.49	28,760
1984	3,153,210	1,363,038	1,201,892	3,054,942	37.39	81,705
1985	1,016,286	416,535	367,290	1,004,696	38.30	26,232
1986	23,665,041	9,172,215	8,087,827	23,859,978	39.21	608,518
1987	8,331,924	3,041,486	2,681,905	8,566,192	40.13	213,461
1988	7,528,759	2,576,530	2,271,919	7,891,906	41.06	192,204
1989	557,739	178,072	157,019	595,929	41.99	14,192
1990	3,656,126	1,083,402	955,316	3,980,454	42.93	92,720
1991	236,538	64,632	56,991	262,335	43.87	5,980
1992	2,527,977	632,386	557,622	2,855,147	44.81	63,717
1993	3,330,238	754,399	665,210	3,830,611	45.77	83,693
1994	719,957	146,277	128,983	842,959	46.72	18,043
1996	8,346,020	1,301,353	1,147,500	10,119,627	48.65	208,009
1998	3,841,831	415,955	366,779	4,819,693	50.59	95,270
1999	4,631,526	390,160	344,033	5,908,527	51.57	114,573
2000	8,704,638	525,281	463,180	11,288,081	52.54	214,847
2001	20,116,277	730,523	644,157	26,512,817	53.52	495,381
2002	20,327,580	244,236	215,361	27,226,872	54.51	499,484
	205,771,417	79,883,493	70,439,236	207,352,178		5,391,852

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 38.5 2.62

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 356.5 OVERHEAD CONDUCTORS & DEVICES- SCE 500 KV LINE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 40-SQUARE							
NET SALVAGE PERCENT.. -30							
1969	22,599,173	40.00	2.50	564,979.33	6.50	.8375	18,926,807
1981	54,342	40.00	2.50	1,358.55	18.50	.5375	29,209
				566,337.88			18,956,016
NET SALVAGE ADJUSTMENT				169,901.36			5,686,805
TOTAL	22,653,515			736,239.24			24,642,821

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.25

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 357 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 48-S1.5						
NET SALVAGE PERCENT.. -10						
1964	96,103	66,029	66,948	38,765	18.02	2,151
1966	202,070	134,100	135,966	86,311	19.04	4,533
1971	15,025	9,011	9,136	7,392	21.83	339
1974	3,356,916	1,871,044	1,897,082	1,795,526	23.68	75,825
1979	31,078	14,898	15,105	19,081	27.08	705
1980	5,890	2,725	2,763	3,716	27.81	134
1985	510,363	190,651	193,304	368,095	31.70	11,612
1987	48,949	16,412	16,640	37,204	33.37	1,115
1988	33,310	10,512	10,658	25,983	34.23	759
1989	316	93	94	254	35.10	7
1990	383,199	105,464	106,932	314,587	35.99	8,741
1995	1,427,350	241,322	244,680	1,325,405	40.62	32,629
1997	842,510	105,187	106,651	820,110	42.55	19,274
1998	1,055	108	110	1,051	43.53	24
1999	1,563,826	124,715	126,451	1,593,758	44.52	35,799
2000	613,977	35,052	35,540	639,835	45.51	14,059
2001	268,995	9,232	9,360	286,535	46.50	6,162
2002	1,043,430	11,937	12,103	1,135,670	47.50	23,909
	10,444,362	2,948,492	2,989,523	8,499,278		237,777

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 35.7 2.28

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 358 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R3						
NET SALVAGE PERCENT.. -10						
1964	25,243	21,658	20,317	7,450	8.80	847
1966	356,731	295,676	277,365	115,039	9.86	11,667
1968	25,252	20,130	18,883	8,894	11.01	808
1973	107,606	76,193	71,474	46,893	14.25	3,291
1974	5,465,773	3,764,934	3,531,772	2,480,578	14.95	165,925
1977	183,546	115,326	108,184	93,717	17.15	5,465
1979	685,054	401,421	376,561	376,998	18.69	20,171
1980	21,258	11,996	11,253	12,131	19.48	623
1984	108,470	51,366	48,185	71,132	22.78	3,123
1985	1,162,089	523,080	490,686	787,612	23.63	33,331
1987	135,124	54,356	50,990	97,646	25.37	3,849
1988	96,333	36,399	34,145	71,821	26.26	2,735
1989	1,258,607	444,691	417,151	967,317	27.15	35,629
1990	1,292,110	424,264	397,989	1,023,332	28.06	36,469
1992	51,869	14,407	13,515	43,541	29.90	1,456
1993	7,344	1,852	1,737	6,341	30.83	206
1994	177,282	40,114	37,630	157,380	31.77	4,954
1995	462,924	92,677	86,938	422,278	32.72	12,906
1996	20,555	3,572	3,351	19,260	33.68	572
1997	239,498	35,302	33,116	230,332	34.64	6,649
1998	7,765	940	882	7,660	35.60	215
1999	976,032	92,011	86,313	987,322	36.57	26,998
2000	2,298,219	154,716	145,134	2,382,907	37.55	63,460
2001	1,193,419	48,178	45,194	1,267,567	38.53	32,898
2002	2,193,151	29,432	27,609	2,384,857	39.51	60,361
	18,551,254	6,754,691	6,336,374	14,070,005		534,608
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					26.3	2.88

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R2.5						
NET SALVAGE PERCENT.. -10						
1942	6,560	6,313	6,476	740	5.63	131
1945	2,474	2,335	2,395	326	6.39	51
1949	6,756	6,190	6,349	1,083	7.52	144
1950	14,792	13,437	13,783	2,488	7.84	317
1952	38,263	34,122	35,001	7,088	8.52	832
1953	7,082	6,253	6,414	1,376	8.88	155
1954	6,972	6,091	6,248	1,421	9.26	153
1955	36,586	31,596	32,410	7,835	9.67	810
1956	32,296	27,561	28,271	7,255	10.09	719
1957	75,227	63,386	65,019	17,731	10.53	1,684
1958	51,167	42,550	43,646	12,638	10.98	1,151
1959	32,313	26,491	27,173	8,371	11.46	730
1960	88,491	71,467	73,308	24,032	11.96	2,009
1961	33,886	26,938	27,632	9,643	12.48	773
1962	100,842	78,857	80,888	30,038	13.01	2,309
1963	45,042	34,603	35,494	14,052	13.57	1,036
1964	46,463	35,051	35,954	15,155	14.14	1,072
1965	28,746	21,271	21,819	9,802	14.73	665
1966	13,834	10,033	10,291	4,926	15.33	321
1967	97,683	69,371	71,158	36,293	15.95	2,275
1968	20,699	14,374	14,744	8,025	16.59	484
1969	128,436	87,155	89,400	51,880	17.24	3,009
1970	258,669	171,348	175,762	108,774	17.90	6,077
1971	53,929	34,828	35,725	23,597	18.58	1,270
1972	209,669	131,878	135,275	95,361	19.27	4,949
1973	293,993	179,871	184,505	138,887	19.97	6,955
1974	332,514	197,586	202,676	163,089	20.69	7,883
1975	98,984	57,054	58,524	50,358	21.42	2,351
1976	110,230	61,548	63,134	58,119	22.16	2,623
1977	191,481	103,398	106,062	104,567	22.91	4,564
1978	259,921	135,523	139,014	146,899	23.67	6,206
1979	822,823	413,543	424,197	480,908	24.44	19,677
1980	604,248	292,190	299,717	364,956	25.22	14,471
1981	298,432	138,466	142,033	186,242	26.02	7,158
1982	634,829	282,118	289,386	408,926	26.82	15,247

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R2.5						
NET SALVAGE PERCENT.. -10						
1983	628,350	266,797	273,670	417,515	27.63	15,111
1984	443,249	179,330	183,950	303,624	28.45	10,672
1985	676,450	259,912	266,608	477,487	29.28	16,308
1986	2,064,066	750,845	770,188	1,500,285	30.12	49,810
1987	1,381,750	473,913	486,122	1,033,803	30.97	33,381
1988	1,517,392	488,555	501,141	1,167,990	31.83	36,695
1989	1,073,422	323,057	331,380	849,384	32.69	25,983
1990	1,528,605	427,092	438,095	1,243,371	33.57	37,038
1991	801,607	206,686	212,011	669,757	34.45	19,441
1992	215,159	50,861	52,171	184,504	35.33	5,222
1993	797,292	170,931	175,335	701,686	36.23	19,368
1994	1,121,491	215,764	221,322	1,012,318	37.13	27,264
1995	1,466,795	249,927	256,366	1,357,109	38.03	35,685
1996	1,054,351	155,875	159,891	999,895	38.95	25,671
1997	481,768	60,520	62,079	467,866	39.86	11,738
1998	1,630,823	167,910	172,236	1,621,669	40.79	39,757
1999	1,586,234	127,549	130,834	1,614,023	41.71	38,696
2000	572,456	32,870	33,717	595,985	42.65	13,974
2001	528,566	18,199	18,668	562,755	43.59	12,910
2002	1,160,884	13,281	13,623	1,263,349	44.53	28,371
	25,815,042	7,554,670	7,749,290	20,647,256		623,356
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					33.1	2.41

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 362 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 38-S0						
NET SALVAGE PERCENT.. 0						
1929	9,640	9,407	9,640			
1935	35,712	32,762	35,712			
1938	1,270	1,127	1,270			
1939	12,143	10,657	12,143			
1940	1,053	913	1,053			
1941	5,369	4,603	5,369			
1942	104,403	88,440	104,403			
1943	3,397	2,843	3,397			
1945	80,545	65,749	80,545			
1946	10,283	8,289	10,283			
1947	36,496	29,033	36,496			
1948	259,920	204,115	259,920			
1949	188,317	145,889	188,317			
1950	137,358	104,928	137,358			
1951	54,517	41,073	54,517			
1952	225,561	167,502	225,561			
1953	126,409	92,506	126,409			
1954	262,735	189,458	262,735			
1955	424,231	301,204	424,231			
1956	339,426	237,327	339,426			
1957	254,786	175,344	254,786			
1958	337,056	228,120	337,056			
1959	226,691	150,931	226,691			
1960	479,854	314,064	479,854			
1961	175,577	112,878	175,577			
1962	959,099	605,767	959,099			
1963	454,572	281,835	452,560	2,012	14.44	139
1964	269,185	163,718	262,892	6,293	14.89	423
1965	266,554	159,026	255,358	11,196	15.33	730
1966	544,078	318,122	510,828	33,250	15.78	2,107
1967	455,823	261,004	419,110	36,713	16.24	2,261
1968	570,239	319,619	513,232	57,007	16.70	3,414
1969	984,204	539,737	866,688	117,516	17.16	6,848
1970	2,170,475	1,163,592	1,868,450	302,025	17.63	17,131
1971	826,357	432,763	694,914	131,443	18.10	7,262

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 362 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 38-S0						
NET SALVAGE PERCENT.. 0						
1972	2,062,235	1,054,008	1,692,485	369,750	18.58	19,900
1973	1,681,722	837,834	1,345,361	336,361	19.07	17,638
1974	2,211,380	1,073,183	1,723,275	488,105	19.56	24,954
1975	1,021,052	482,345	774,531	246,521	20.05	12,295
1976	929,351	426,758	685,271	244,080	20.55	11,877
1977	1,779,374	793,245	1,273,762	505,612	21.06	24,008
1978	2,657,712	1,149,195	1,845,332	812,380	21.57	37,662
1979	4,222,966	1,768,156	2,839,235	1,383,731	22.09	62,641
1980	2,239,337	906,260	1,455,237	784,100	22.62	34,664
1981	2,560,854	1,000,013	1,605,781	955,073	23.16	41,238
1982	4,693,455	1,766,147	2,836,009	1,857,446	23.70	78,373
1983	3,627,985	1,312,605	2,107,729	1,520,256	24.25	62,691
1984	4,897,749	1,698,539	2,727,447	2,170,302	24.82	87,442
1985	7,125,197	2,364,140	3,796,243	3,328,954	25.39	131,113
1986	6,657,430	2,107,742	3,384,529	3,272,901	25.97	126,026
1987	5,938,319	1,788,028	2,871,145	3,067,174	26.56	115,481
1988	10,600,431	3,024,303	4,856,306	5,744,125	27.16	211,492
1989	4,563,279	1,227,066	1,970,374	2,592,905	27.78	93,337
1990	4,463,240	1,126,522	1,808,925	2,654,315	28.41	93,429
1991	4,965,704	1,169,423	1,877,813	3,087,891	29.05	106,296
1992	4,505,211	983,037	1,578,522	2,926,689	29.71	98,509
1993	5,268,282	1,056,291	1,696,150	3,572,132	30.38	117,582
1994	3,635,828	662,084	1,063,148	2,572,680	31.08	82,776
1995	5,307,172	867,192	1,392,503	3,914,669	31.79	123,142
1996	7,972,575	1,149,645	1,846,055	6,126,520	32.52	188,392
1997	7,553,299	938,120	1,506,396	6,046,903	33.28	181,698
1998	11,457,184	1,188,110	1,907,820	9,549,364	34.06	280,369
1999	19,247,683	1,586,009	2,546,751	16,700,932	34.87	478,948
2000	14,769,021	890,572	1,430,046	13,338,975	35.71	373,536
2001	22,738,273	843,590	1,354,604	21,383,669	36.59	584,413
2002	19,710,942	254,271	408,298	19,302,644	37.51	514,600
	212,357,577	44,458,778	70,802,963	141,554,614		4,456,837
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					31.8	2.10

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 364 POLES, TOWERS AND FIXTURES - WOOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

SURVIVOR CURVE.. IOWA 38-R0.5
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1955	1,061,536	795,547	1,145,658	22,032	12.11	1,819
1956	609,877	449,479	647,290	23,575	12.54	1,880
1957	2,286,122	1,656,455	2,385,442	129,292	12.97	9,969
1958	516,054	367,332	528,991	38,668	13.41	2,884
1960	1,480,329	1,015,121	1,461,864	166,498	14.31	11,635
1961	537,798	361,809	521,037	70,541	14.76	4,779
1962	514,543	339,146	488,400	77,597	15.23	5,095
1963	582,756	376,350	541,977	99,055	15.69	6,313
1964	579,433	366,173	527,322	110,054	16.17	6,806
1965	581,563	359,394	517,559	122,160	16.65	7,337
1966	549,228	331,800	477,821	126,330	17.13	7,375
1967	780,231	460,282	662,847	195,407	17.62	11,090
1968	501,985	288,902	416,045	136,139	18.12	7,513
1969	2,078,633	1,165,427	1,678,318	608,178	18.63	32,645
1970	1,158,173	632,281	910,541	363,449	19.14	18,989
1971	1,076,716	571,941	823,646	360,742	19.65	18,358
1972	1,256,658	648,172	933,425	448,899	20.18	22,245
1973	1,121,436	561,649	808,824	424,756	20.70	20,520
1974	1,895,214	919,577	1,324,273	760,462	21.24	35,803
1975	2,603,441	1,222,263	1,760,167	1,103,618	21.78	50,671
1976	3,991,279	1,811,482	2,608,695	1,781,712	22.32	79,826
1977	2,270,671	994,599	1,432,311	1,065,427	22.87	46,586
1978	4,416,862	1,862,767	2,682,550	2,175,998	23.43	92,872
1979	2,709,248	1,098,790	1,582,355	1,397,818	23.99	58,267
1980	3,076,680	1,197,721	1,724,825	1,659,523	24.55	67,598
1981	7,394,252	2,756,503	3,969,609	4,164,068	25.12	165,767
1982	2,847,512	1,014,540	1,461,028	1,671,235	25.69	65,054
1983	5,034,560	1,709,586	2,461,956	3,076,060	26.27	117,094
1984	5,334,456	1,721,642	2,479,317	3,388,585	26.85	126,204
1985	12,100,863	3,699,113	5,327,051	7,983,898	27.44	290,958
1986	7,171,563	2,071,578	2,983,256	4,905,463	28.02	175,070
1987	18,026,140	4,899,685	7,055,981	12,772,773	28.61	446,444
1988	5,650,710	1,439,575	2,073,116	4,142,665	29.20	141,872
1989	18,361,850	4,358,736	6,276,967	13,921,068	29.80	467,150
1990	20,128,367	4,434,883	6,386,625	15,754,579	30.39	518,413

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 364 POLES, TOWERS AND FIXTURES - WOOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 38-R0.5						
NET SALVAGE PERCENT.. -10						
1991	10,263,211	2,082,919	2,999,588	8,289,944	30.99	267,504
1992	12,131,711	2,251,282	3,242,046	10,102,836	31.59	319,811
1993	9,762,697	1,641,988	2,364,608	8,374,359	32.19	260,154
1994	25,514,836	3,847,892	5,541,306	22,525,014	32.79	686,948
1995	20,204,944	2,691,501	3,876,000	18,349,438	33.40	549,384
1996	16,051,664	1,853,967	2,669,877	14,986,953	34.01	440,663
1997	12,359,825	1,212,746	1,746,462	11,849,346	34.61	342,368
1998	11,171,700	895,859	1,290,117	10,998,753	35.23	312,198
1999	8,306,946	519,018	747,432	8,390,209	35.84	234,102
2000	5,231,312	234,781	338,105	5,416,338	36.45	148,596
2001	3,444,219	92,822	133,672	3,654,969	37.07	98,596
2002	9,470,907	85,428	123,024	10,294,974	37.69	273,149
	284,200,711	65,370,503	94,139,326	218,481,457		7,076,374

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 30.9 2.49

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 364.1 POLES, TOWERS AND FIXTURES - STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -5						
1955	23,948	19,452	24,656	489	11.32	43
1956	5,912	4,736	6,003	205	11.85	17
1957	32,139	25,384	32,175	1,571	12.39	127
1958	9,253	7,197	9,122	594	12.96	46
1960	8,097	6,098	7,729	773	14.14	55
1961	6,616	4,897	6,207	740	14.75	50
1962	8,463	6,151	7,797	1,089	15.39	71
1963	8,103	5,780	7,326	1,182	16.03	74
1964	9,814	6,863	8,699	1,606	16.70	96
1965	11,054	7,572	9,598	2,009	17.38	116
1966	8,781	5,888	7,463	1,757	18.07	97
1967	8,895	5,834	7,395	1,945	18.77	104
1968	6,895	4,418	5,600	1,640	19.49	84
1969	8,941	5,592	7,088	2,300	20.22	114
1970	17,748	10,820	13,715	4,920	20.97	235
1971	15,074	8,952	11,347	4,481	21.72	206
1972	15,382	8,886	11,263	4,888	22.49	217
1973	11,961	6,717	8,514	4,045	23.26	174
1974	19,255	10,493	13,300	6,918	24.05	288
1975	29,743	15,709	19,911	11,319	24.85	455
1976	35,081	17,931	22,728	14,107	25.66	550
1977	18,408	9,092	11,524	7,804	26.48	295
1978	49,502	23,587	29,897	22,080	27.31	808
1979	27,935	12,818	16,247	13,085	28.15	465
1980	27,435	12,099	15,336	13,471	29.00	465
1981	71,417	30,205	38,285	36,703	29.86	1,229
1982	30,992	12,542	15,897	16,645	30.73	542
1983	53,383	20,627	26,145	29,907	31.60	946
1984	36,637	13,472	17,076	21,393	32.49	658
1985	126,261	44,068	55,857	76,717	33.38	2,298
1986	93,732	30,943	39,221	59,198	34.28	1,727
1987	237,562	73,884	93,649	155,791	35.19	4,427
1988	112,060	32,687	41,431	76,232	36.11	2,111
1989	322,769	87,913	111,431	227,476	37.03	6,143
1990	244,356	61,783	78,311	178,263	37.96	4,696

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 364.1 POLES, TOWERS AND FIXTURES - STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -5						
1991	79,410	18,527	23,483	59,898	38.89	1,540
1992	160,338	34,210	43,362	124,993	39.84	3,137
1993	58,167	11,262	14,275	46,800	40.78	1,148
1994	407,345	70,658	89,560	338,152	41.74	8,101
1995	366,272	56,226	71,267	313,319	42.69	7,339
1996	12,311,202	1,639,113	2,077,606	10,849,156	43.66	248,492
1997	254,341	28,735	36,422	230,636	44.62	5,169
1998	1,700,832	157,514	199,652	1,586,222	45.59	34,793
1999	5,616,943	404,588	512,823	5,384,967	46.57	115,632
2000	11,387,333	588,270	745,643	11,211,057	47.54	235,824
2001	8,636,118	268,411	340,216	8,727,708	48.52	179,879
2002	11,187,746	115,122	145,919	11,601,214	49.51	234,321
	53,919,651	4,053,726	5,138,171	51,477,465		1,105,404
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					46.6	2.05

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 53-O1						
NET SALVAGE PERCENT.. -10						
1955	525,552	259,050	546,536	31,571	29.25	1,079
1956	543,693	262,370	553,540	44,522	29.75	1,497
1957	1,010,278	476,972	1,006,301	105,005	30.25	3,471
1958	473,279	218,551	461,092	59,515	30.75	1,935
1960	839,406	370,170	780,974	142,373	31.75	4,484
1961	348,664	150,152	316,786	66,744	32.25	2,070
1962	437,724	183,980	388,155	93,341	32.75	2,850
1963	491,327	201,375	424,855	115,605	33.25	3,477
1964	626,212	250,184	527,831	161,002	33.75	4,770
1965	536,329	208,729	440,370	149,592	34.25	4,368
1966	542,204	205,349	433,239	163,185	34.75	4,696
1967	1,002,098	369,163	778,849	323,459	35.25	9,176
1968	728,405	260,805	550,239	251,007	35.75	7,021
1969	1,728,066	600,676	1,267,288	633,585	36.25	17,478
1970	1,296,295	437,188	922,366	503,559	36.75	13,702
1971	1,220,183	398,902	841,592	500,609	37.25	13,439
1972	1,451,628	459,397	969,222	627,569	37.75	16,624
1973	1,125,809	344,644	727,120	511,270	38.25	13,367
1974	1,152,676	340,950	719,326	548,618	38.75	14,158
1975	1,882,680	537,204	1,133,377	937,571	39.25	23,887
1976	2,747,140	755,464	1,593,855	1,427,999	39.75	35,925
1977	2,045,047	541,242	1,141,896	1,107,656	40.25	27,519
1978	3,092,105	786,044	1,658,372	1,742,944	40.75	42,772
1979	2,147,116	523,617	1,104,711	1,257,117	41.25	30,476
1980	2,140,273	499,818	1,054,501	1,299,799	41.75	31,133
1981	6,175,955	1,377,732	2,906,698	3,886,853	42.25	91,997
1982	2,669,099	567,824	1,197,978	1,738,031	42.75	40,656
1983	5,251,409	1,062,885	2,242,443	3,534,107	43.25	81,713
1984	4,251,023	815,984	1,721,539	2,954,586	43.75	67,533
1985	473,253	85,947	181,328	339,250	44.25	7,667
1986	5,062,845	867,113	1,829,409	3,739,721	44.75	83,569
1987	2,137,150	343,696	725,120	1,625,745	45.25	35,928
1988	14,648,911	2,204,368	4,650,710	11,463,092	45.75	250,559
1989	18,131,924	2,541,008	5,360,943	14,584,173	46.25	315,333
1990	11,533,361	1,495,762	3,155,714	9,530,983	46.75	203,871

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 53-O1						
NET SALVAGE PERCENT.. -10						
1991	9,730,474	1,161,332	2,450,143	8,253,378	47.25	174,675
1992	4,550,521	496,052	1,046,556	3,959,017	47.75	82,911
1993	14,895,594	1,468,110	3,097,374	13,287,779	48.25	275,394
1994	7,910,711	697,883	1,472,373	7,229,409	48.75	148,296
1995	8,634,912	672,487	1,418,793	8,079,610	49.25	164,053
1996	8,898,741	600,042	1,265,951	8,522,664	49.75	171,310
1997	7,386,343	421,686	889,660	7,235,317	50.25	143,986
1998	9,324,946	435,941	919,735	9,337,706	50.75	183,994
1999	10,367,806	376,351	794,014	10,610,573	51.25	207,036
2000	12,601,069	327,124	690,156	13,171,020	51.75	254,512
2001	13,638,092	213,027	449,438	14,552,463	52.25	278,516
2002	10,448,452	54,018	113,966	11,379,331	52.75	215,722
	218,856,780	27,928,368	58,922,434	181,820,025		3,810,605

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 47.7 1.74

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 366 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R1.5						
NET SALVAGE PERCENT.. -5						
1956	670,881	422,373	470,235	234,190	22.02	10,635
1957	17,412	10,779	12,000	6,283	22.57	278
1958	13,047	7,939	8,839	4,860	23.13	210
1960	16,994	9,964	11,093	6,751	24.29	278
1961	943,757	542,641	604,132	386,813	24.88	15,547
1962	45,785	25,811	28,736	19,338	25.47	759
1963	121,575	67,120	74,726	52,928	26.08	2,029
1964	422,425	228,293	254,163	189,383	26.69	7,096
1965	129,504	68,438	76,193	59,786	27.32	2,188
1966	111,690	57,676	64,212	53,063	27.95	1,898
1967	811,950	409,393	455,784	396,764	28.59	13,878
1968	734,600	361,368	402,317	369,013	29.23	12,624
1969	256,328	122,864	136,787	132,357	29.89	4,428
1970	865,918	404,146	449,943	459,271	30.55	15,033
1971	802,661	364,508	405,813	436,981	31.21	14,001
1972	626,048	276,219	307,519	349,831	31.89	10,970
1973	426,546	182,643	203,340	244,533	32.57	7,508
1974	529,817	219,908	244,827	311,481	33.26	9,365
1975	721,226	289,814	322,655	434,632	33.95	12,802
1976	375,510	145,886	162,417	231,869	34.65	6,692
1977	566,902	212,563	236,650	358,597	35.36	10,141
1978	914,914	330,659	368,128	592,532	36.07	16,427
1979	806,133	280,256	312,014	534,426	36.79	14,526
1980	1,387,862	463,407	515,919	941,336	37.51	25,096
1981	1,645,882	526,575	586,245	1,141,931	38.24	29,862
1982	1,551,508	474,552	528,327	1,100,756	38.98	28,239
1983	1,938,483	565,843	629,963	1,405,444	39.71	35,393
1984	2,305,965	640,182	712,726	1,708,537	40.46	42,228
1985	807,659	212,604	236,696	611,346	41.21	14,835
1986	2,068,865	515,054	573,418	1,598,890	41.96	38,105
1987	3,502,542	821,224	914,283	2,763,386	42.72	64,686
1988	8,270,510	1,819,305	2,025,463	6,658,573	43.48	153,141
1989	5,049,619	1,037,091	1,154,611	4,147,489	44.24	93,750
1990	14,180,385	2,703,916	3,010,316	11,879,088	45.01	263,921
1991	12,390,708	2,179,216	2,426,158	10,584,085	45.79	231,144

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 366 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R1.5						
NET SALVAGE PERCENT.. -5						
1992	6,821,566	1,098,033	1,222,459	5,940,185	46.57	127,554
1993	57,372,387	8,379,524	9,329,067	50,911,939	47.35	1,075,226
1994	31,173,609	4,081,716	4,544,244	28,188,045	48.14	585,543
1995	25,028,025	2,901,249	3,230,010	23,049,416	48.93	471,069
1996	33,588,584	3,385,729	3,769,390	31,498,623	49.72	633,520
1997	32,635,859	2,792,814	3,109,288	31,158,364	50.52	616,753
1998	34,572,458	2,421,282	2,695,655	33,605,426	51.33	654,694
1999	34,476,600	1,882,422	2,095,732	34,104,698	52.14	654,099
2000	32,987,032	1,291,937	1,438,336	33,198,048	52.95	626,970
2001	29,420,538	691,971	770,383	30,121,182	53.77	560,186
2002	41,614,847	327,717	364,853	43,330,736	54.59	793,749
	425,723,116	46,254,624	51,496,065	395,513,205		8,009,076

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 49.4 1.88

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 29-L1						
NET SALVAGE PERCENT.. -5						
1955	8,367	6,198	7,540	1,245	8.54	146
1956	1,649,430	1,207,482	1,468,877	263,025	8.78	29,957
1958	54,269	38,765	47,157	9,825	9.27	1,060
1960	49,763	34,648	42,149	10,102	9.77	1,034
1961	2,905,950	1,997,041	2,429,359	621,889	10.02	62,065
1962	2,123	1,439	1,751	478	10.28	46
1963	345,070	230,510	280,411	81,913	10.55	7,764
1964	1,329,952	875,853	1,065,457	330,993	10.81	30,619
1965	1,877,927	1,218,390	1,482,146	489,677	11.08	44,195
1966	871,705	556,771	677,300	237,990	11.36	20,950
1967	2,898,481	1,821,782	2,216,160	827,245	11.64	71,069
1968	2,056,329	1,270,873	1,545,991	613,154	11.93	51,396
1969	958,007	582,420	708,502	297,405	12.21	24,357
1970	4,711,237	2,812,750	3,421,652	1,525,147	12.51	121,914
1971	740,165	433,896	527,826	249,347	12.81	19,465
1972	1,357,217	780,800	949,827	475,251	13.11	36,251
1973	1,315,115	741,804	902,389	478,482	13.42	35,654
1974	1,221,221	674,737	820,804	461,478	13.74	33,586
1975	2,709,042	1,465,483	1,782,730	1,061,764	14.06	75,517
1976	1,788,274	945,979	1,150,764	726,924	14.39	50,516
1977	2,305,925	1,192,209	1,450,298	970,923	14.72	65,959
1978	3,660,321	1,847,492	2,247,436	1,595,901	15.06	105,970
1979	3,177,191	1,564,608	1,903,313	1,432,738	15.40	93,035
1980	6,022,821	2,889,418	3,514,917	2,809,045	15.75	178,352
1981	8,604,272	4,015,829	4,885,173	4,149,313	16.11	257,561
1982	6,268,592	2,844,092	3,459,779	3,122,243	16.47	189,572
1983	6,048,984	2,661,251	3,237,357	3,114,076	16.85	184,812
1984	11,801,518	5,033,465	6,123,106	6,268,488	17.22	364,024
1985	16,576,699	6,836,894	8,316,941	9,088,593	17.61	516,104
1986	12,404,905	4,936,532	6,005,189	7,019,961	18.01	389,781
1987	21,531,581	8,256,500	10,043,862	12,564,298	18.41	682,471
1988	31,805,293	11,698,464	14,230,941	19,164,617	18.84	1,017,230
1989	37,332,688	13,123,933	15,964,994	23,234,328	19.29	1,204,475
1990	47,122,287	15,729,184	19,134,228	30,344,173	19.78	1,534,084
1991	26,581,373	8,373,132	10,185,743	17,724,699	20.30	873,138

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 29-L1						
NET SALVAGE PERCENT.. -5						
1992	42,238,566	12,462,489	15,160,361	29,190,133	20.85	1,400,006
1993	30,989,902	8,483,021	10,319,420	22,219,977	21.44	1,036,380
1994	29,203,240	7,328,553	8,915,034	21,748,368	22.07	985,427
1995	33,737,546	7,633,963	9,286,559	26,137,864	22.75	1,148,917
1996	44,856,471	8,995,965	10,943,406	36,155,889	23.46	1,541,172
1997	45,086,075	7,801,694	9,490,600	37,849,779	24.22	1,562,749
1998	66,961,056	9,674,533	11,768,870	58,540,239	25.01	2,340,673
1999	56,403,481	6,431,689	7,824,017	51,399,638	25.85	1,988,381
2000	62,005,998	5,143,398	6,256,838	58,849,460	26.71	2,203,274
2001	60,246,574	3,030,101	3,686,056	59,572,847	27.61	2,157,655
2002	63,682,780	1,083,244	1,317,744	65,549,175	28.53	2,297,553
	805,505,783	186,769,274	227,200,974	618,580,099		27,036,316
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					22.9	3.36

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 368 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 36-R3						
NET SALVAGE PERCENT.. -5						
1940	1,566	1,644	1,644			
1941	3,997	4,197	4,197			
1942	3,525	3,684	3,701			
1943	5,547	5,770	5,824			
1944	7,785	8,047	8,174			
1945	18,985	19,498	19,934			
1946	33,973	34,651	35,672			
1947	82,390	83,430	86,510			
1948	137,267	138,048	144,130			
1949	112,783	112,572	118,422			
1950	173,341	171,743	182,008			
1951	449,398	441,857	471,868			
1952	357,352	348,654	375,220			
1953	522,556	505,996	548,684			
1954	574,406	551,861	598,938	4,188	3.06	1,369
1955	695,031	662,497	719,012	10,771	3.32	3,244
1956	1,069,238	1,010,767	1,096,992	25,708	3.59	7,161
1957	1,005,446	942,545	1,022,950	32,768	3.86	8,489
1958	1,694,115	1,574,256	1,708,551	70,270	4.14	16,973
1959	1,265,057	1,164,795	1,264,160	64,150	4.43	14,481
1960	1,279,836	1,166,846	1,266,386	77,442	4.74	16,338
1961	1,089,555	983,182	1,067,054	76,979	5.06	15,213
1962	1,360,226	1,213,573	1,317,099	111,138	5.41	20,543
1963	990,813	873,273	947,769	92,585	5.78	16,018
1964	1,100,862	957,783	1,039,488	116,417	6.17	18,868
1965	795,148	682,034	740,216	94,689	6.59	14,369
1966	871,080	736,006	798,792	115,842	7.03	16,478
1967	993,990	826,289	896,777	146,913	7.50	19,588
1968	1,569,152	1,281,511	1,390,833	256,777	8.00	32,097
1969	1,688,089	1,352,944	1,468,359	304,134	8.52	35,696
1970	2,824,018	2,218,280	2,407,514	557,705	9.07	61,489
1971	3,207,429	2,465,903	2,676,261	691,539	9.64	71,736
1972	3,102,295	2,331,002	2,529,852	727,558	10.24	71,051
1973	4,656,244	3,414,028	3,705,268	1,183,788	10.86	109,004
1974	4,512,153	3,223,099	3,498,051	1,239,710	11.51	107,707

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 368 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 36-R3						
NET SALVAGE PERCENT.. -5						
1975	3,920,881	2,724,993	2,957,453	1,159,472	12.17	95,273
1976	2,996,691	2,022,587	2,195,127	951,399	12.86	73,981
1977	6,273,266	4,105,633	4,455,871	2,131,058	13.56	157,158
1978	8,811,719	5,581,916	6,058,091	3,194,214	14.28	223,684
1979	10,407,641	6,368,852	6,912,158	4,015,865	15.02	267,368
1980	10,857,562	6,403,627	6,949,900	4,450,540	15.78	282,037
1981	15,091,596	8,561,689	9,292,059	6,554,117	16.55	396,019
1982	12,545,383	6,831,337	7,414,096	5,758,556	17.33	332,288
1983	13,136,129	6,842,675	7,426,401	6,366,534	18.14	350,967
1984	24,606,791	12,236,465	13,280,318	12,556,813	18.95	662,629
1985	23,155,117	10,955,381	11,889,949	12,422,924	19.78	628,055
1986	21,092,848	9,454,764	10,261,319	11,886,171	20.63	576,160
1987	19,528,462	8,269,620	8,975,075	11,529,810	21.48	536,770
1988	17,120,921	6,816,866	7,398,391	10,578,576	22.35	473,314
1989	19,265,021	7,174,968	7,787,041	12,441,231	23.23	535,567
1990	18,298,077	6,340,284	6,881,153	12,331,828	24.12	511,270
1991	9,411,162	3,010,960	3,267,815	6,613,905	25.03	264,239
1992	12,406,044	3,639,561	3,950,040	9,076,306	25.94	349,896
1993	13,565,459	3,616,484	3,924,995	10,318,737	26.86	384,167
1994	13,616,404	3,256,908	3,534,744	10,762,480	27.80	387,140
1995	15,827,146	3,351,952	3,637,896	12,980,607	28.74	451,656
1996	20,347,987	3,745,352	4,064,856	17,300,530	29.69	582,706
1997	2,984,662	466,637	506,444	2,627,451	30.64	85,752
1998	40,187,171	5,143,757	5,582,554	36,613,976	31.61	1,158,304
1999	20,096,101	2,010,916	2,182,461	18,918,445	32.57	580,855
2000	24,462,530	1,749,193	1,898,411	23,787,246	33.55	709,009
2001	22,407,671	959,945	1,041,835	22,486,220	34.53	651,208
2002	26,161,963	373,593	405,463	27,064,598	35.51	762,168
	486,837,053	173,529,180	188,298,226	322,880,680		13,147,552

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 24.6 2.70

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 369 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 37-S2						
NET SALVAGE PERCENT.. -10						
1955	1,004,228	930,558	1,104,651			
1956	440,917	404,643	485,009			
1957	264,412	240,303	290,853			
1958	119,964	107,917	130,883	1,077	6.74	160
1959	72,487	64,546	78,282	1,454	7.05	206
1960	415,850	366,177	444,104	13,331	7.38	1,806
1961	162,414	141,388	171,477	7,178	7.72	930
1962	88,130	75,800	91,931	5,012	8.07	621
1963	147,238	125,067	151,683	10,279	8.43	1,219
1964	104,925	87,971	106,692	8,726	8.80	992
1965	157,080	129,919	157,568	15,220	9.18	1,658
1966	48,509	39,545	47,961	5,399	9.58	564
1967	263,485	211,578	256,605	33,229	9.99	3,326
1968	123,514	97,633	118,411	17,454	10.41	1,677
1969	365,749	284,363	344,879	57,445	10.85	5,294
1970	228,747	174,701	211,880	39,742	11.31	3,514
1971	301,867	226,328	274,494	57,560	11.78	4,886
1972	420,969	309,513	375,382	87,684	12.27	7,146
1973	424,966	306,001	371,122	96,341	12.78	7,538
1974	662,026	466,430	565,693	162,536	13.30	12,221
1975	1,153,413	793,860	962,804	305,950	13.85	22,090
1976	821,989	551,826	669,262	234,926	14.42	16,292
1977	448,582	293,252	355,660	137,780	15.01	9,179
1978	4,705,970	2,991,020	3,627,549	1,549,018	15.62	99,169
1979	2,051,070	1,265,264	1,534,529	721,648	16.25	44,409
1980	2,593,107	1,548,863	1,878,482	973,936	16.91	57,595
1981	3,818,697	2,203,617	2,672,576	1,527,991	17.59	86,867
1982	3,179,488	1,767,605	2,143,775	1,353,662	18.30	73,971
1983	5,756,211	3,075,371	3,729,851	2,601,981	19.03	136,730
1984	8,525,144	4,364,362	5,293,157	4,084,501	19.78	206,497
1985	11,121,513	5,435,417	6,592,147	5,641,517	20.56	274,393
1986	4,850,431	2,253,704	2,733,322	2,602,152	21.37	121,767
1987	7,748,266	3,409,237	4,134,768	4,388,325	22.20	197,672
1988	7,946,346	3,295,350	3,996,645	4,744,336	23.05	205,828
1989	13,157,398	5,116,254	6,205,061	8,268,077	23.92	345,655

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 369 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 37-S2						
NET SALVAGE PERCENT.. -10						
1990	9,371,389	3,393,567	4,115,764	6,192,764	24.82	249,507
1991	7,292,022	2,443,265	2,963,224	5,058,000	25.73	196,580
1992	6,224,768	1,913,805	2,321,088	4,526,157	26.66	169,773
1993	14,479,941	4,042,510	4,902,810	11,025,125	27.61	399,316
1994	12,197,476	3,056,444	3,706,896	9,710,328	28.57	339,878
1995	21,617,789	4,793,961	5,814,180	17,965,388	29.54	608,172
1996	9,381,525	1,806,976	2,191,525	8,128,153	30.52	266,322
1997	4,666,464	761,754	923,866	4,209,244	31.51	133,584
1998	14,467,246	1,935,139	2,346,963	13,567,008	32.50	417,446
1999	21,374,675	2,224,249	2,697,599	20,814,544	33.50	621,330
2000	9,352,318	695,438	843,436	9,444,114	34.50	273,742
2001	15,505,612	690,775	837,781	16,218,392	35.50	456,856
2002	12,778,485	189,761	230,145	13,826,189	36.50	378,800
	242,404,812	71,103,027	86,204,425	180,440,873		6,463,178
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					27.9	2.67

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 370 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 23-R1						
NET SALVAGE PERCENT.. 0						
1922	36	36	36			
1929	2,120	2,120	2,120			
1930	356	356	356			
1931	491	491	491			
1933	321	321	321			
1937	342	342	342			
1938	628	628	628			
1939	281	281	281			
1940	788	788	788			
1941	3,060	3,060	3,060			
1942	1,464	1,464	1,464			
1943	1,982	1,982	1,982			
1944	2,596	2,596	2,596			
1945	4,531	4,531	4,531			
1946	5,980	5,980	5,980			
1947	5,064	5,064	5,064			
1948	2,228	2,228	2,228			
1949	8,078	8,078	8,078			
1950	14,865	14,865	14,865			
1951	107,821	107,821	107,821			
1952	25,024	25,024	25,024			
1953	33,308	33,308	33,308			
1954	40,421	40,421	40,421			
1955	43,566	43,566	43,566			
1956	40,316	40,316	40,316			
1957	57,180	56,557	54,592	2,588	0.25	2,588
1958	70,591	68,840	66,448	4,143	0.57	4,143
1959	100,131	96,166	92,825	7,306	0.91	7,306
1960	113,182	107,081	103,361	9,821	1.24	7,920
1961	134,644	125,569	121,207	13,437	1.55	8,669
1962	144,843	133,198	128,571	16,272	1.85	8,796
1963	133,558	121,070	116,864	16,694	2.15	7,765
1964	156,046	139,427	134,583	21,463	2.45	8,760
1965	84,083	73,993	71,422	12,661	2.76	4,587
1966	135,542	117,447	113,367	22,175	3.07	7,223

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 370 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 23-R1						
NET SALVAGE PERCENT.. 0						
1967	103,616	88,302	85,234	18,382	3.40	5,406
1968	158,278	132,542	127,937	30,341	3.74	8,113
1969	242,895	199,805	192,864	50,031	4.08	12,263
1970	290,108	234,117	225,984	64,124	4.44	14,442
1971	322,391	254,979	246,121	76,270	4.81	15,857
1972	718,911	556,653	537,314	181,597	5.19	34,990
1973	847,786	642,113	619,806	227,980	5.58	40,857
1974	898,193	664,304	641,226	256,967	5.99	42,899
1975	335,523	242,147	233,735	101,788	6.40	15,904
1976	423,807	297,936	287,585	136,222	6.83	19,945
1977	1,197,492	818,486	790,051	407,441	7.28	55,967
1978	959,923	637,293	615,153	344,770	7.73	44,602
1979	1,492,217	959,496	926,162	566,055	8.21	68,947
1980	1,941,619	1,208,075	1,166,106	775,513	8.69	89,242
1981	1,730,571	1,039,035	1,002,938	727,633	9.19	79,177
1982	1,201,945	694,484	670,357	531,588	9.71	54,746
1983	1,329,451	737,579	711,955	617,496	10.24	60,302
1984	3,016,539	1,601,481	1,545,844	1,470,695	10.79	136,302
1985	3,410,636	1,727,487	1,667,473	1,743,163	11.35	153,583
1986	1,770,643	852,919	823,288	947,355	11.92	79,476
1987	5,259,712	2,398,955	2,315,614	2,944,098	12.51	235,340
1988	5,562,400	2,389,607	2,306,590	3,255,810	13.12	248,156
1989	7,840,313	3,156,510	3,046,851	4,793,462	13.74	348,869
1990	5,499,803	2,063,526	1,991,838	3,507,965	14.37	244,117
1991	4,278,397	1,486,315	1,434,679	2,843,718	15.01	189,455
1992	14,352,966	4,580,031	4,420,918	9,932,048	15.66	634,230
1993	6,361,178	1,844,742	1,780,654	4,580,524	16.33	280,497
1994	11,709,742	3,055,072	2,948,937	8,760,805	17.00	515,341
1995	6,598,188	1,526,161	1,473,141	5,125,047	17.68	289,878
	91,330,710	37,475,167	36,185,262	55,145,448		4,086,660

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 13.5 4.47

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 370.1 ELECTRONIC METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 12-S2						
NET SALVAGE PERCENT.. 0						
1996	7,531,929	3,741,109	2,900,703	4,631,226	6.04	766,759
1997	2,336	1,010	783	1,553	6.81	228
1998	16,140,488	5,850,927	4,536,571	11,603,917	7.65	1,516,852
1999	6,758,092	1,937,545	1,502,293	5,255,799	8.56	613,995
2000	8,309,433	1,724,207	1,336,880	6,972,553	9.51	733,181
2001	7,821,267	977,658	758,036	7,063,231	10.50	672,689
2002	8,127,704	338,925	262,789	7,864,915	11.50	683,906
	54,691,249	14,571,381	11,298,055	43,393,194		4,987,610
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					8.7	9.12

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R1						
NET SALVAGE PERCENT.. -20						
1965	1,003,656	896,425	1,005,512	198,875	7.67	25,929
1966	213,427	187,039	209,800	46,312	8.09	5,725
1967	331,929	285,313	320,033	78,282	8.51	9,199
1968	190,043	160,092	179,574	48,478	8.94	5,423
1969	341,280	281,474	315,727	93,809	9.38	10,001
1970	82,619	66,624	74,732	24,411	9.84	2,481
1971	278,615	219,560	246,279	88,059	10.30	8,549
1972	305,578	234,941	263,531	103,163	10.78	9,570
1973	211,604	158,627	177,931	75,994	11.26	6,749
1974	170,482	124,384	139,520	65,058	11.76	5,532
1975	297,419	210,930	236,598	120,305	12.27	9,805
1976	166,582	114,682	128,638	71,260	12.79	5,572
1977	77,533	51,730	58,025	35,015	13.32	2,629
1978	207,508	133,967	150,270	98,740	13.86	7,124
1979	91,606	57,085	64,032	45,895	14.42	3,183
1980	185,191	111,181	124,711	97,518	14.99	6,506
1981	532,894	307,586	345,016	294,457	15.57	18,912
1982	110,356	61,089	68,523	63,904	16.16	3,954
1983	193,604	102,525	115,001	117,324	16.76	7,000
1984	216,684	109,469	122,790	137,231	17.37	7,900
1985	581,552	279,354	313,349	384,513	17.99	21,374
1986	115,021	52,353	58,724	79,301	18.62	4,259
1987	330,275	141,886	159,152	237,178	19.26	12,315
1988	685,069	276,466	310,110	511,973	19.91	25,714
1989	834,611	315,182	353,537	647,996	20.56	31,517
1990	556,993	195,638	219,445	448,947	21.22	21,157
1991	1,053,735	341,789	383,382	881,100	21.89	40,251
1992	654,712	194,607	218,289	567,365	22.57	25,138
1993	1,561,175	421,517	472,812	1,400,598	23.25	60,241
1994	1,218,109	295,708	331,693	1,130,038	23.93	47,223
1995	1,312,957	282,496	316,873	1,258,675	24.62	51,124
1996	1,498,224	280,468	314,599	1,483,270	25.32	58,581
1997	1,807,630	287,847	322,876	1,846,280	26.02	70,956
1998	1,367,898	178,921	200,694	1,440,784	26.73	53,901
1999	1,031,626	105,597	118,447	1,119,504	27.44	40,798

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R1						
NET SALVAGE PERCENT.. -20						
2000	1,953,834	143,021	160,425	2,184,176	28.17	77,536
2001	1,464,506	65,024	72,937	1,684,470	28.89	58,306
2002	2,099,294	30,986	34,757	2,484,396	29.63	83,847
	25,335,831	7,763,583	8,708,344	21,694,654		945,981

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 22.9 3.73

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. -20						
1956	153,758	156,889	167,522	16,988	5.24	3,242
1957	147,891	149,269	159,386	18,083	5.56	3,252
1958	272,109	271,674	290,086	36,445	5.88	6,198
1959	137,960	136,133	145,359	20,193	6.22	3,246
1960	258,881	252,347	269,450	41,207	6.57	6,272
1961	87,596	84,271	89,982	15,133	6.94	2,181
1962	72,254	68,575	73,223	13,482	7.32	1,842
1963	160,392	150,069	160,240	32,230	7.71	4,180
1964	260,576	240,147	256,423	56,268	8.12	6,930
1965	53,317	48,350	51,627	12,353	8.55	1,445
1966	1,890	1,685	1,799	469	8.99	52
1967	94,109	82,439	88,026	24,905	9.45	2,635
1968	167,379	143,933	153,688	47,167	9.92	4,755
1969	121,442	102,390	109,329	36,401	10.41	3,497
1970	261,602	215,979	230,617	83,305	10.92	7,629
1971	143,167	115,604	123,439	48,361	11.45	4,224
1972	208,312	164,333	175,470	74,504	11.99	6,214
1973	345,267	265,745	283,756	130,564	12.55	10,404
1974	322,813	242,071	258,477	128,899	13.13	9,817
1975	297,996	217,418	232,153	125,442	13.72	9,143
1976	288,496	204,463	218,320	127,875	14.33	8,924
1977	329,385	226,327	241,666	153,596	14.96	10,267
1978	714,626	475,341	507,557	349,994	15.60	22,436
1979	584,298	375,610	401,067	300,091	16.25	18,467
1980	571,485	354,275	378,286	307,496	16.92	18,174
1981	893,947	533,257	569,398	503,338	17.60	28,599
1982	538,125	308,281	329,174	316,576	18.29	17,309
1983	1,326,332	727,520	776,827	814,771	19.00	42,883
1984	768,324	402,540	429,822	492,167	19.72	24,958
1985	505,098	251,781	268,845	337,273	20.46	16,485
1987	2,466,934	1,103,016	1,177,772	1,782,549	21.96	81,173
1988	1,969,544	828,627	884,786	1,478,667	22.73	65,054
1989	3,509,047	1,382,424	1,476,116	2,734,740	23.51	116,322
1990	2,693,479	988,076	1,055,042	2,177,133	24.30	89,594
1991	4,303,381	1,459,363	1,558,270	3,605,787	25.11	143,600

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. -20						
1992	907,022	282,338	301,473	786,953	25.92	30,361
1993	4,722,754	1,337,484	1,428,130	4,239,175	26.74	158,533
1994	2,250,040	573,220	612,069	2,087,979	27.57	75,734
1995	3,122,301	704,391	752,130	2,994,631	28.42	105,371
1996	3,971,349	780,132	833,005	3,932,614	29.27	134,356
1997	5,276,921	880,824	940,521	5,391,784	30.13	178,951
1998	3,678,836	505,914	540,202	3,874,401	30.99	125,021
1999	2,735,492	293,464	313,353	2,969,237	31.87	93,167
2000	1,800,892	138,309	147,683	2,013,387	32.76	61,459
2001	2,906,903	134,648	143,774	3,344,510	33.65	99,391
2002	782,015	12,106	12,926	925,492	34.55	26,787
	57,185,737	18,373,052	19,618,266	49,004,615		1,890,534
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					25.9	3.31

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 39-R1						
NET SALVAGE PERCENT.. -15						
1947	4,332	4,038	4,872	110	7.39	15
1958	4,120	3,307	3,990	748	11.78	63
1960	38,435	29,840	36,005	8,195	12.67	647
1961	294,333	224,516	270,905	67,578	13.13	5,147
1962	1,216,519	911,167	1,099,429	299,568	13.60	22,027
1963	3,559,030	2,615,353	3,155,729	937,156	14.08	66,559
1964	566,408	408,018	492,321	159,048	14.57	10,916
1965	41,067	28,988	34,977	12,250	15.06	813
1966	94,524	65,309	78,803	29,900	15.57	1,920
1967	78,775	53,240	64,240	26,351	16.08	1,639
1968	115,099	76,030	91,739	40,625	16.60	2,447
1969	200,574	129,354	156,081	74,579	17.13	4,354
1970	386,456	243,056	293,275	151,149	17.67	8,554
1971	114,460	70,132	84,622	47,007	18.22	2,580
1972	17,378	10,366	12,508	7,477	18.77	398
1973	576,009	333,921	402,915	259,495	19.34	13,418
1974	690,764	388,610	468,903	325,476	19.92	16,339
1975	392,972	214,390	258,687	193,231	20.50	9,426
1976	309,613	163,500	197,282	158,773	21.09	7,528
1977	209,725	107,037	129,153	112,031	21.69	5,165
1978	385,080	189,625	228,805	214,037	22.30	9,598
1979	445,114	211,049	254,655	257,226	22.92	11,223
1980	3,483,935	1,588,187	1,916,333	2,090,192	23.54	88,793
1981	287,417	125,700	151,672	178,858	24.17	7,400
1982	3,473,077	1,453,031	1,753,251	2,240,788	24.81	90,318
1983	606,190	242,179	292,217	404,902	25.45	15,910
1984	1,308,342	497,268	600,012	904,581	26.11	34,645
1985	7,132,214	2,573,802	3,105,592	5,096,454	26.76	190,450
1986	9,378,954	3,202,303	3,863,952	6,921,845	27.42	252,438
1987	4,555,417	1,465,273	1,768,023	3,470,707	28.09	123,557
1988	9,975,852	3,012,608	3,635,063	7,837,167	28.76	272,502
1989	1,592,921	448,989	541,758	1,290,101	29.44	43,821
1990	2,224,550	582,510	702,866	1,855,367	30.12	61,599
1991	1,904,799	460,009	555,055	1,635,464	30.81	53,082
1992	2,054,276	455,002	549,013	1,813,404	31.49	57,587

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 39-R1						
NET SALVAGE PERCENT.. -15						
1993	2,525,614	507,118	611,897	2,292,559	32.19	71,220
1994	2,903,131	523,826	632,057	2,706,544	32.88	82,316
1995	916,089	146,437	176,693	876,809	33.58	26,111
1996	3,506,879	487,176	587,835	3,445,076	34.29	100,469
1997	1,824,737	215,301	259,786	1,838,662	35.00	52,533
1998	5,513,506	535,141	645,710	5,694,822	35.71	159,474
1999	1,583,254	119,987	144,778	1,675,964	36.43	46,005
2000	915,695	49,704	59,974	993,075	37.16	26,724
2001	1,014,925	33,264	40,137	1,127,027	37.89	29,745
2002	18,244,874	199,325	240,509	20,741,096	38.63	536,917
	96,667,435	25,404,986	30,654,079	80,513,474		2,624,392
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					30.7	2.71

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 20-SQUARE							
NET SALVAGE PERCENT.. 0							
1979	23,005					1.0000	23,005
1982	5,241					1.0000	5,241
1985	56,459	20.00	5.00	2,822.95	2.50	.8750	49,402
1986	849,800	20.00	5.00	42,490.00	3.50	.8250	701,085
1987	38,481	20.00	5.00	1,924.05	4.50	.7750	29,823
1988	33,188	20.00	5.00	1,659.40	5.50	.7250	24,061
1989	10,335,873	20.00	5.00	516,793.65	6.50	.6750	6,976,714
1990	1,345,986	20.00	5.00	67,299.30	7.50	.6250	841,241
1992	48,238	20.00	5.00	2,411.90	9.50	.5250	25,325
1993	140,853	20.00	5.00	7,042.65	10.50	.4750	66,905
1994	46,856	20.00	5.00	2,342.80	11.50	.4250	19,914
1995	877,474	20.00	5.00	43,873.70	12.50	.3750	329,053
1996	538,551	20.00	5.00	26,927.55	13.50	.3250	175,029
1997	90,294	20.00	5.00	4,514.70	14.50	.2750	24,831
1998	443,007	20.00	5.00	22,150.35	15.50	.2250	99,677
1999	669,276	20.00	5.00	33,463.80	16.50	.1750	117,123
2000	2,054,544	20.00	5.00	102,727.20	17.50	.1250	256,818
2001	1,482,766	20.00	5.00	74,138.30	18.50	.0750	111,207
2002	839,748	20.00	5.00	41,987.40	19.50	.0250	20,994
TOTAL	19,919,640			994,569.70			9,897,448

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.99

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - PC EQUIP

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 5-SQUARE							
NET SALVAGE PERCENT.. 0							
1995	24,977					1.0000	24,977
1996	3,576,320					1.0000	3,576,320
1997	2,716,808					1.0000	2,716,808
1998	7,522,688	5.00	20.00	1,504,537.60	0.50	.9000	6,770,419
1999	3,345,538	5.00	20.00	669,107.60	1.50	.7000	2,341,877
2000	8,542,711	5.00	20.00	1,708,542.20	2.50	.5000	4,271,356
2001	1,445,002	5.00	20.00	289,000.40	3.50	.3000	433,501
2002	11,480,902	5.00	20.00	2,296,180.40	4.50	.1000	1,148,090
TOTAL	38,654,946			6,467,368.20			21,283,348

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 16.73

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 10-SQUARE							
NET SALVAGE PERCENT.. 0							
1978	15,438					1.0000	15,438
1979	64,656					1.0000	64,656
1982	262,056					1.0000	262,056
1983	180,890					1.0000	180,890
1984	158,214					1.0000	158,214
1985	194,477					1.0000	194,477
1986	352,472					1.0000	352,472
1987	845,445					1.0000	845,445
1988	332,473					1.0000	332,473
1989	147,322					1.0000	147,322
1990	92,554					1.0000	92,554
1991	337,134					1.0000	337,134
1992	50,703					1.0000	50,703
1993	93,530	10.00	10.00	9,353.00	0.50	.9500	88,854
1994	277,713	10.00	10.00	27,771.30	1.50	.8500	236,056
1995	21,691	10.00	10.00	2,169.10	2.50	.7500	16,268
1996	2,972	10.00	10.00	297.20	3.50	.6500	1,932
1997	389,977	10.00	10.00	38,997.70	4.50	.5500	214,487
1998	47,234	10.00	10.00	4,723.40	5.50	.4500	21,255
1999	98,555	10.00	10.00	9,855.50	6.50	.3500	34,494
2000	33,506	10.00	10.00	3,350.60	7.50	.2500	8,377
2001	2,320,311	10.00	10.00	232,031.10	8.50	.1500	348,047
2002	1,333,600	10.00	10.00	133,360.00	9.50	.0500	66,680
TOTAL	7,652,923			461,908.90			4,070,284

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 6.04

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 393 STORES EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 20-SQUARE							
NET SALVAGE PERCENT.. 0							
1953	63,220					1.0000	63,220
1954	16,665					1.0000	16,665
1955	7,879					1.0000	7,879
1956	24,283					1.0000	24,283
1957	21,255					1.0000	21,255
1958	4,843					1.0000	4,843
1959	16,813					1.0000	16,813
1960	22,920					1.0000	22,920
1961	7,163					1.0000	7,163
1962	99,204					1.0000	99,204
1963	37,701					1.0000	37,701
1966	7,696					1.0000	7,696
1967	6,541					1.0000	6,541
1968	10,235					1.0000	10,235
1969	4,756					1.0000	4,756
1970	15,045					1.0000	15,045
1972	6,102					1.0000	6,102
1973	17,676					1.0000	17,676
1974	32,148					1.0000	32,148
1975	12,042					1.0000	12,042
1976	6,733					1.0000	6,733
1977	16,809					1.0000	16,809
1978	33,911					1.0000	33,911
1979	43,187					1.0000	43,187
1980	49,833					1.0000	49,833
1981	28,200					1.0000	28,200
1982	16,098					1.0000	16,098
1983	27,998	20.00	5.00	1,399.90	0.50	.9750	27,298
1984	195,856	20.00	5.00	9,792.80	1.50	.9250	181,167
1985	156,387	20.00	5.00	7,819.35	2.50	.8750	136,839
1986	95,929	20.00	5.00	4,796.45	3.50	.8250	79,141
1987	91,317	20.00	5.00	4,565.85	4.50	.7750	70,771
1988	6,285	20.00	5.00	314.25	5.50	.7250	4,557
1989	13,442	20.00	5.00	672.10	6.50	.6750	9,073
1994	11,199	20.00	5.00	559.95	11.50	.4250	4,760
TOTAL	1,227,371			29,920.65			1,142,564

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.44

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 20-SQUARE							
NET SALVAGE PERCENT.. 0							
1986	33,498	20.00	5.00	1,674.90	3.50	.8250	27,636
1987	367,503	20.00	5.00	18,375.15	4.50	.7750	284,815
1988	185,033	20.00	5.00	9,251.65	5.50	.7250	134,149
1989	504,922	20.00	5.00	25,246.10	6.50	.6750	340,822
1990	1,035,131	20.00	5.00	51,756.55	7.50	.6250	646,957
1991	574,258	20.00	5.00	28,712.90	8.50	.5750	330,198
1992	392,467	20.00	5.00	19,623.35	9.50	.5250	206,045
1993	242,906	20.00	5.00	12,145.30	10.50	.4750	115,380
1994	1,452,458	20.00	5.00	72,622.90	11.50	.4250	617,295
1995	345,750	20.00	5.00	17,287.50	12.50	.3750	129,656
1996	1,344,415	20.00	5.00	67,220.75	13.50	.3250	436,935
1997	815,217	20.00	5.00	40,760.85	14.50	.2750	224,185
1998	140,443	20.00	5.00	7,022.15	15.50	.2250	31,600
1999	382,362	20.00	5.00	19,118.10	16.50	.1750	66,913
2000	2,637,596	20.00	5.00	131,879.80	17.50	.1250	329,700
2001	230,361	20.00	5.00	11,518.05	18.50	.0750	17,277
2002	1,988,711	20.00	5.00	99,435.55	19.50	.0250	49,718
TOTAL	12,673,031			633,651.55			3,989,281

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 5.00

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 395 LABORATORY EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 15-SQUARE							
NET SALVAGE PERCENT.. 0							
1970	2,080					1.0000	2,080
1972	43,765					1.0000	43,765
1973	2,392					1.0000	2,392
1975	1,352					1.0000	1,352
1976	1,801					1.0000	1,801
1978	315					1.0000	315
1980	630					1.0000	630
1982	1,224					1.0000	1,224
1983	4,080					1.0000	4,080
1984	1,938					1.0000	1,938
1985	115,702					1.0000	115,702
1986	23,132					1.0000	23,132
1987	24,730					1.0000	24,730
1988	138,581	15.00	6.67	9,243.35	0.50	.9667	133,966
1989	64,472	15.00	6.67	4,300.28	1.50	.9000	58,025
1990	176,146	15.00	6.67	11,748.94	2.50	.8333	146,782
1991	438,006	15.00	6.67	29,215.00	3.50	.7667	335,819
1992	127,003	15.00	6.67	8,471.10	4.50	.7000	88,902
1993	38,992	15.00	6.67	2,600.77	5.50	.6333	24,694
1994	101,225	15.00	6.67	6,751.71	6.50	.5667	57,364
1996	4,228	15.00	6.67	282.01	8.50	.4333	1,832
1998	38,789	15.00	6.67	2,587.23	10.50	.3000	11,637
TOTAL	1,350,583			75,200.39			1,082,162

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 5.57

ARIZONA PUBLIC SERVICE COMPANY

ACOUNNT 397 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 19-S1.5						
NET SALVAGE PERCENT.. 0						
1969	363,208	340,834	351,920	11,288	1.17	9,648
1972	3,774	3,391	3,501	273	1.93	141
1974	3,036	2,646	2,732	304	2.44	125
1976	243,523	205,339	212,018	31,505	2.98	10,572
1977	731,814	605,869	625,575	106,239	3.27	32,489
1978	958,522	778,895	804,229	154,293	3.56	43,341
1979	215,198	171,362	176,936	38,262	3.87	9,887
1980	1,009,386	786,816	812,407	196,979	4.19	47,012
1981	209,687	159,698	164,892	44,795	4.53	9,889
1982	1,602,372	1,189,921	1,228,623	373,749	4.89	76,431
1983	162,286	117,365	121,182	41,104	5.26	7,814
1984	793,955	557,436	575,567	218,388	5.66	38,584
1985	1,005,942	684,041	706,290	299,652	6.08	49,285
1986	6,386,604	4,191,528	4,327,858	2,058,746	6.53	315,275
1987	1,746,485	1,103,080	1,138,958	607,527	7.00	86,790
1988	3,091,380	1,869,357	1,930,158	1,161,222	7.51	154,623
1989	3,839,875	2,212,920	2,284,895	1,554,980	8.05	193,165
1990	9,415,685	5,143,789	5,311,091	4,104,594	8.62	476,171
1991	3,084,441	1,586,020	1,637,606	1,446,835	9.23	156,754
1992	4,075,032	1,956,015	2,019,635	2,055,397	9.88	208,036
1993	782,270	346,702	357,979	424,291	10.58	40,103
1994	4,854,731	1,964,710	2,028,612	2,826,119	11.31	249,878
1995	1,212,234	440,890	455,230	757,004	12.09	62,614
1996	7,982,909	2,563,312	2,646,684	5,336,225	12.90	413,661
1997	7,825,969	2,158,402	2,228,604	5,597,365	13.76	406,785
1998	4,151,079	950,182	981,087	3,169,992	14.65	216,382
1999	12,243,599	2,203,848	2,275,528	9,968,071	15.58	639,799
2000	6,666,819	866,686	894,875	5,771,944	16.53	349,180
2001	380,053	29,796	30,765	349,288	17.51	19,948
2002	9,267,823	243,744	251,672	9,016,151	18.50	487,360
	94,309,691	35,434,594	36,587,109	57,722,582		4,811,742

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 12.0 5.10

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 20-SQUARE							
NET SALVAGE PERCENT.. 0							
1976	5,074					1.0000	5,074
1977	469					1.0000	469
1981	25,332					1.0000	25,332
1983	9,787	20.00	5.00	489.35	0.50	.9750	9,542
1984	11,419	20.00	5.00	570.95	1.50	.9250	10,563
1985	5,828	20.00	5.00	291.40	2.50	.8750	5,100
1986	67,697	20.00	5.00	3,384.85	3.50	.8250	55,850
1987	69,632	20.00	5.00	3,481.60	4.50	.7750	53,965
1988	11,188	20.00	5.00	559.40	5.50	.7250	8,111
1989	103,445	20.00	5.00	5,172.25	6.50	.6750	69,825
1990	111,815	20.00	5.00	5,590.75	7.50	.6250	69,884
1991	2,956	20.00	5.00	147.80	8.50	.5750	1,700
1993	4,383	20.00	5.00	219.15	10.50	.4750	2,082
1994	601,135	20.00	5.00	30,056.75	11.50	.4250	255,482
2000	23,461	20.00	5.00	1,173.05	17.50	.1250	2,933
2001	27,403	20.00	5.00	1,370.15	18.50	.0750	2,055
2002	255,380	20.00	5.00	12,769.00	19.50	.0250	6,385
TOTAL	1,336,404			65,276.45			584,352

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.88

PINNACLE WEST ENERGY CORPORATION

Phoenix, Arizona

ADDENDUM TO DEPRECIATION STUDY PREPARED FOR
ARIZONA PUBLIC SERVICE COMPANY

RECOMMENDED REMAINING LIFE DEPRECIATION ACCRUAL RATES

AS OF DECEMBER 31, 2002

Gannett Fleming
Valuation and Rate Division

Harrisburg, Pennsylvania   Calgary, Alberta   Valley Forge, Pennsylvania

PINNACLE WEST ENERGY CORPORATION

Phoenix, Arizona

ADDENDUM TO DEPRECIATION STUDY PREPARED FOR ARIZONA PUBLIC SERVICE COMPANY

RECOMMENDED REMAINING LIFE DEPRECIATION ACCRUAL RATES

AS OF DECEMBER 31, 2002

GANNETT FLEMING, INC. - VALUATION AND RATE DIVISION

Harrisburg, Pennsylvania	Calgary, Alberta	Valley Forge, Pennsylvania

Gannett Fleming

GANNETT FLEMING, INC.
P.O. Box 80794
Valley Forge, PA 19484-0794
Location:
Valley Forge Corporate Center
1010 Adams Avenue
Audubon, PA 19403-2402
Office: (610) 650-8101
Fax: (610) 650-8190
www.gannettfleming.com

June 18, 2003

Pinnacle West Energy Corporation
400 North 5th Street
Phoenix, AZ 85004

Attention Mr. Chris Froggatt
Vice President and Controller

Ladies and Gentlemen:

Pursuant to your request, we have studied the service life and net salvage characteristics of the electric plant of the Pinnacle West Energy Corporation for the purpose of determining recommended annual depreciation accrual rates as of December 31, 2002. The results of our study are presented in the attached report.

This report was prepared as an addendum to the depreciation study report conducted for Arizona Public Service Company (APS). The same depreciation methods and procedures were used in this study as those used in the APS report. The report sets forth a description of the concepts and methods upon which the study was based, our estimates of survivor curves and net salvage, and the ensuing remaining life depreciation accrual rates. The results of the study are summarized in the table on page III-4.

Respectfully submitted,

GANNETT FLEMING, INC.

John F. Wiedmayer

JOHN F. WIEDMAYER, CDP
Supervisor, Depreciation Studies

JFW:krm

CONTENTS

PART I. INTRODUCTION

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

PART III. RESULTS OF STUDY

PART I. INTRODUCTION

PINNACLE WEST ENERGY CORPORATION

DEPRECIATION STUDY

PART I. INTRODUCTION

This report presents the methods used in and the results of the depreciation study conducted for Pinnacle West Energy Corporation ("PWEC" or "the Company"). The assets included in this study consist of three recently constructed electric generating facilities. Two of the facilities are combined-cycle ("CC") plants and the third is a simple-cycle combustion turbine ("CT"). All three facilities, Redhawk CC Units 1 & 2, West Phoenix CC Unit 4 and Saguaro CT Unit 3 are 100 percent owned by PWEC. The primary fuel used to generate electricity at each of these locations is natural gas. The facilities can be grouped into various categories, such as mode of operation (baseload, intermediate and peaking). Redhawk is operating as a baseload plant; West Phoenix CC 4 is operating as an intermediate plant; and Saguaro CT 3 is operating as a peaking plant.

BASIS OF THE STUDY

The purpose of the study was to determine the annual remaining life depreciation accrual rates applicable to electric plant in service as of December 31, 2002. For all accounts, the annual and accrued depreciation were calculated by the straight line method, remaining life basis, and the average service life procedure. The depreciation calculations were based on original cost, attained ages and estimates of survivor curves and net salvage percents for each account as of December 31, 2002.

The service life and net salvage estimates used in the depreciation calculations were based on judgment which incorporated analyses of available historical and projected data, a review of current policies and outlook with management, a field survey of the property, a general knowledge of the electric industry, and comparisons of the survivor curve and net salvage estimates from studies of other electric companies. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for utility property. Iowa type survivor curves were used to depict the estimated survivor curves for most of the property groups. For the power plant structures and equipment in Accounts 341 through 344, probable retirement years were estimated and the life span procedure of calculating depreciation was used to provide for the simultaneous retirement of all associated property, surviving from various years of installation, at the time of the retirement of the major investment. Net salvage amounts will be expensed pursuant to requirements of SFAS 143 since PWEC's assets are not subject to regulation by the Arizona Corporation Commission (ACC). PWEC is a non-regulated corporation and, therefore, must maintain their financial statements in accordance with Generally Accepted Accounting Principles (GAAP).

PART II. METHODS USED

IN THE ESTIMATION OF DEPRECIATION

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

DEPRECIATION

Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption of prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authority.

Depreciation as used in accounting is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight line method of depreciation.

The calculation of annual depreciation based on the straight line method requires the estimation of average life and salvage. These subjects are discussed in the sections which follow.

Service Life Considerations

The service life estimates were based on judgment which considered a number of factors. The primary factors were the statistical analyses of historical and projected plant accounting data for Redhawk; current Company policies and outlook as determined during field reviews of the property and other conversations with management; and the survivor curve estimates from previous studies of this company and other electric companies.

Inasmuch as production plant consists of large generating units, the life span technique was employed in conjunction with the use of interim survivor curves which reflect interim retirements that occur prior to the ultimate retirement of the major unit. An interim survivor curve was estimated for each plant account, inasmuch as the rate of interim retirements differs from account to account. The interim survivor curves estimated for Redhawk were based on the retirement rate method of life analysis which incorporated experienced and estimated aged plant accounting data for the period 2002 through 2012. The 2003 through 2012 retirements were based on planned capital replacements incorporated in the Company's 10-year capital plan for production facilities. The interim survivor curves used for the other two facilities were based on the same interim survivor curves used by Arizona Public Service Company. The statistical support for the interim rates of retirement for production plant accounts are set forth in Appendix A.

The life span estimates for power generating stations were the result of considering experienced life spans of similar generating units, the age of surviving units, general operating characteristics of the units, major refurbishing, and discussions with management personnel concerning the probable long-term outlook for the units.

A typical life span estimate for combined cycle and combustion turbine units ranges from 25-35 years. The life span estimates for Redhawk CC 1 & 2, Saguaro CT 3 and West Phoenix CC 4 are 32, 30 and 30 years, respectively. The life span estimates are within the range typically used for such units and are consistent with management's outlook for the facilities..

A summary of the year in service, life span and probable retirement year for each power production unit follows:

Depreciable Group	Year in Service	Probable Retirement Year	Life Span
OTHER PRODUCTION PLANT			
Redhawk Combined Cycle 1-2	2002	2034	32
Saguaro Combustion Turbine 3	2002	2032	30
West Phoenix Combined Cycle 4	2001	2031	30

The estimated retirement dates should not be interpreted as commitments to retire these plants on these dates, but rather, as reasonable estimates subject to modification in the future as circumstances dictate.

Field Trips

In order to be familiar with the operation of the company and observe representative portions of the plant, field trips were scheduled. A general understanding of the function of the plant and information with respect to the expected causes of retirements were obtained during these field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses. The following is a list of the locations visited in 2002:

Redhawk Combined Cycle Units 1 & 2
West Phoenix Combined Cycle Unit 4

Net Salvage Considerations

The Company expects that there will be interim and final retirements associated with these three generating facilities. Also, the Company expects that there will be interim and final net salvage associated with the retirements. PWEC expects that the removal costs associated with plant retirements will exceed gross salvage. PWEC will treat all removal costs as a current period expense as incurred consistent with SFAS 143. The treatment of cost of removal as an expense is a departure from the typical accounting treatment used for regulatory purposes. However, since these facilities are owned by PWEC, a company whose assets are not regulated by the Arizona Corporation Commission, the Company is compelled to adhere to SFAS 143. The depreciation rates proposed for PWEC do not provide for the prospective recovery of future negative net salvage, i.e., cost of removal exceeds gross salvage. Therefore, the net salvage percent is estimated to be zero.

CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

Group Depreciation Procedures. A group procedure for depreciation is appropriate when considering more than a single item of property. Normally, the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

Remaining Life Annual Accruals. For calculating remaining life accrual rates as of December 31, 2002, the estimated book depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and accrued depreciation calculated by the average service life procedure follow. The detailed depreciation calculations are set forth in Appendix B of the report.

Average Service Life Procedure. In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly-weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future whole life depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account, based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life}{Average\ Service\ Life}.$$

PART III. RESULTS OF STUDY

PART III. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The estimates of survivor curves and net salvage and the determination of remaining life depreciation accrual rates are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the straight line method, average service life procedure using the remaining life technique based on estimates which reflect considerations of current historical evidence and expected future conditions.

The calculated accrued depreciation represents that portion of the depreciable cost which will not be allocated to future annual expense through depreciation accruals, if current forecasts of service life and salvage materialize and are used as a basis for straight line average service life depreciation accounting.

DESCRIPTION OF STATISTICAL SUPPORT

The service life and salvage estimates were based on judgment which incorporated statistical analyses of retirement data, discussions with management and consideration of estimates made for other electric utility companies. The results of the statistical analyses of service life are presented in Appendix A.

The estimated survivor curves for each account are presented in graphical form. The charts depict the estimated smooth survivor curve and original survivor curve(s), when applicable, related to each specific group. For groups where the original survivor curve was plotted, the calculation of the original life table is also presented.

DESCRIPTION OF DEPRECIATION TABULATIONS

A summary of the results of the study, as applied to the original cost of electric plant at December 31, 2002, is presented in Schedule 1 of this report. Schedule 1 sets forth, by depreciable category, the estimated survivor curve, net salvage, original cost, book depreciation reserve at December 31, 2002, future book accruals, calculated annual accrual amount and rate, and composite remaining life for utility plant.

The tables of the calculated annual and accrued depreciation are presented in account sequence in Appendix B. The tables indicate the estimated survivor curve and salvage percent for the account and set forth for each installation year the original cost, the calculated annual accrual rate and amount, and the calculated accrued depreciation factor and amount.

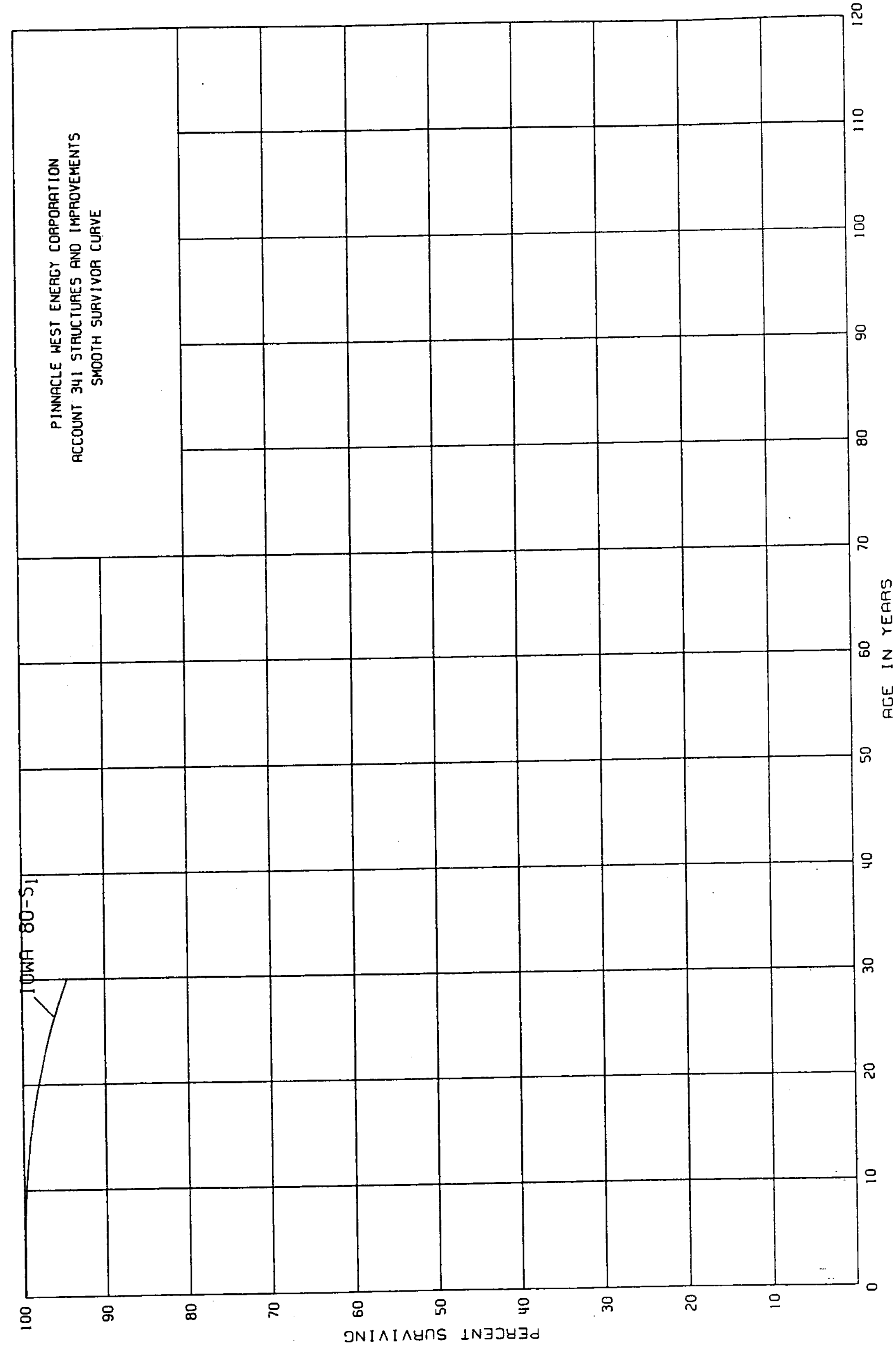
PINNACLE WEST ENERGY CORPORATION

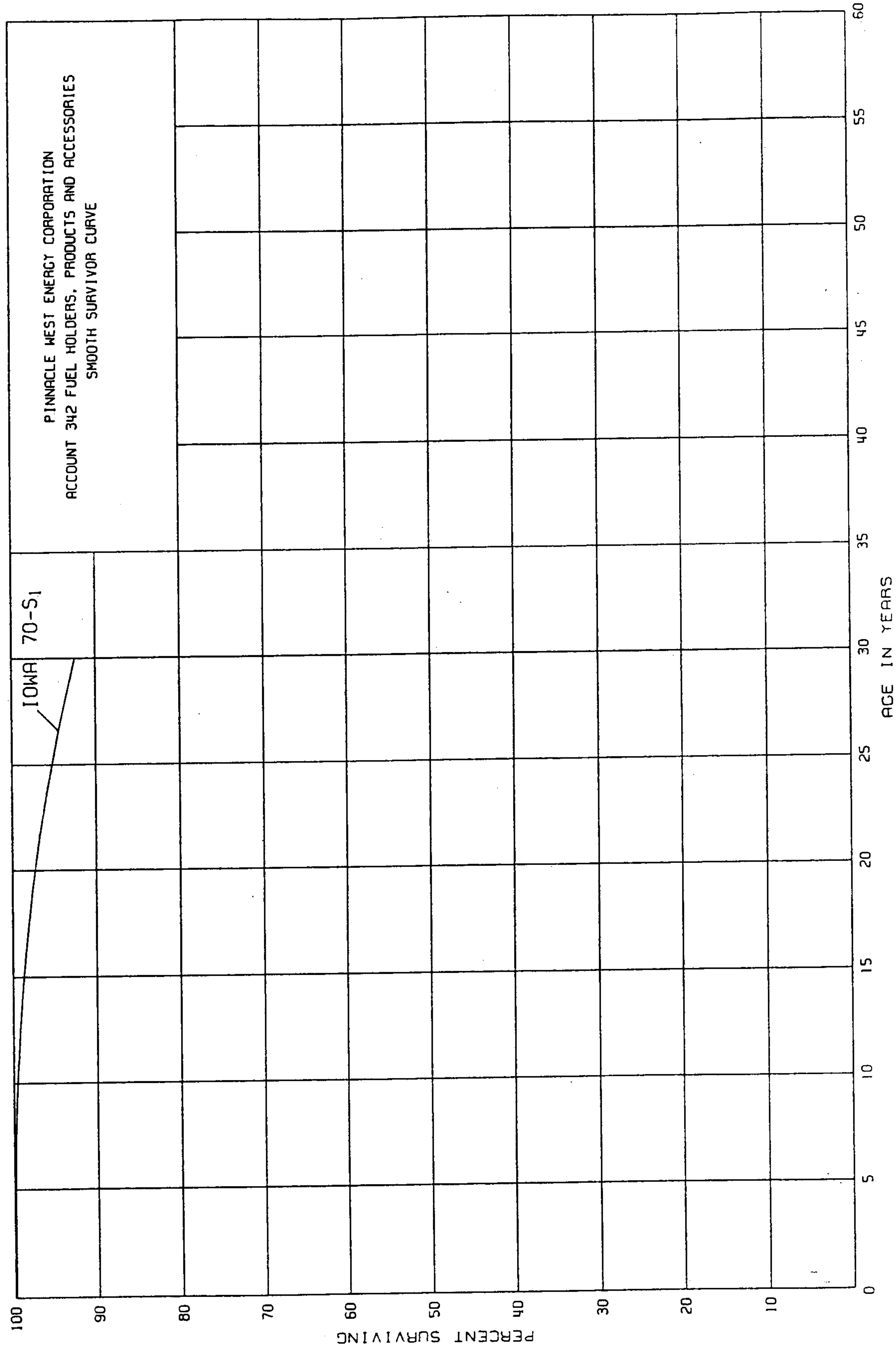
Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

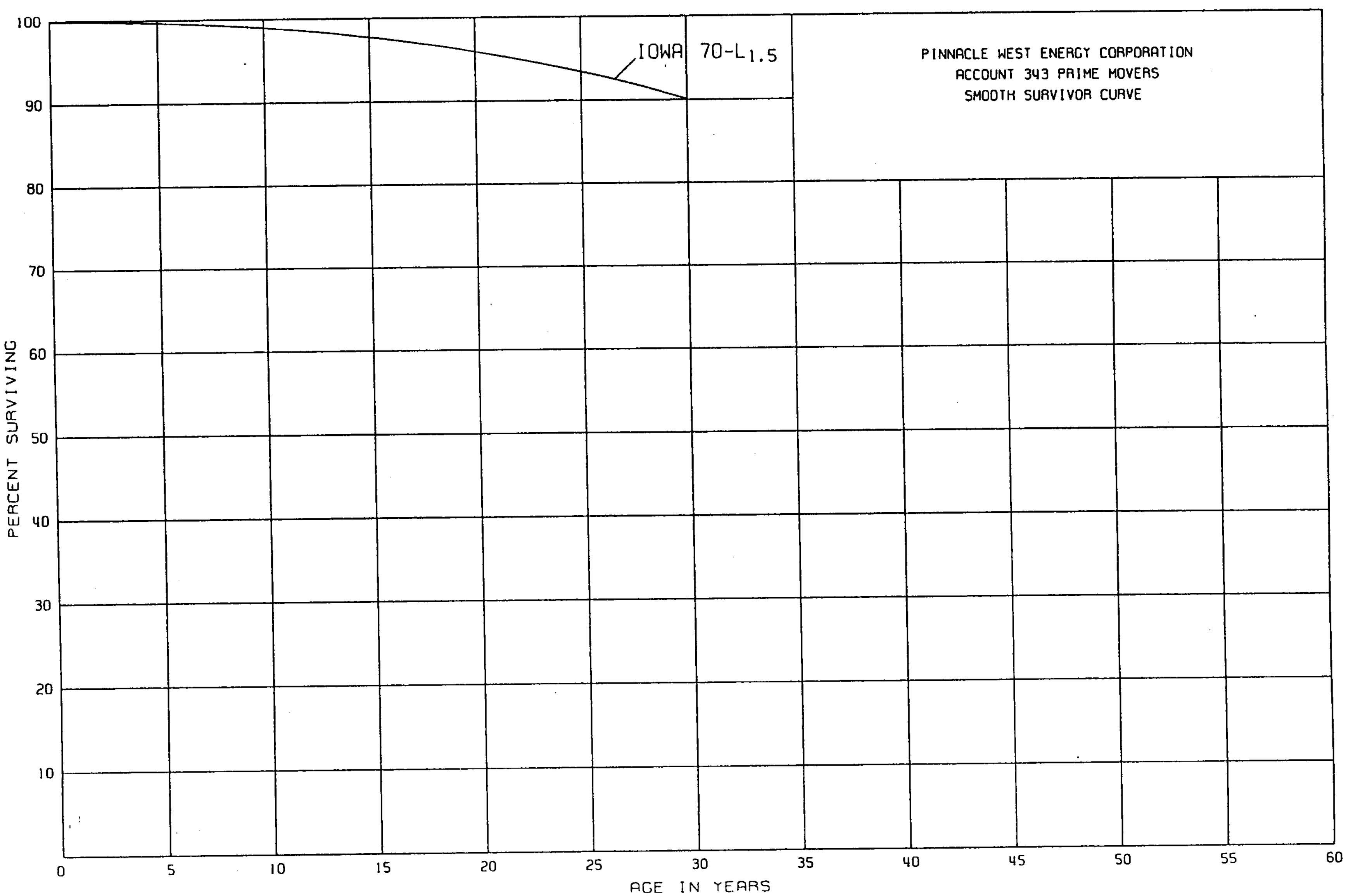
Depreciable Group (1)	Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/02 (5)	Book Accumulated Depreciation (6)	Future Accruals (7)	Composite Remaining Life (8)	Calculated Annual Accrual Amount (9)	Calculated Annual Accrual Rate (10)=(9)/(5)
OTHER PRODUCTION									
341 Structures and Improvements									
West Phoenix CC 4	06-2031	80 - S1	0	3,768,898	234,108	3,534,790	28.1	126,017	3.34
342 Fuel Holders, Products and Accessories									
West Phoenix CC 4	06-2031	70 - S1	0	4,135,109	257,106	3,878,003	27.9	139,196	3.37
343 Prime Movers									
West Phoenix CC 4	06-2031	70 - L1.5	0	57,116,985	3,545,340	53,571,645	27.6	1,942,409	3.40
344 Generators and Devices									
Redhawk CC Units 1 & 2	06-2034	70 - O4	0	546,899,426	9,255,982	537,643,444	24.0	22,355,237	4.09
West Phoenix CC 4	06-2031	37 - R3	0	14,296,553	897,926	13,398,627	26.8	500,696	3.50
Saguaro CT 3	06-2032	37 - R3	0	37,659,176	701,673	36,957,503	27.7	1,331,802	3.54
Total Account 344				598,855,155	10,855,581	587,999,574		24,187,735	4.04
TOTAL OTHER PRODUCTION PLANT				663,876,147	14,892,135	648,984,012		26,395,357	
TRANSMISSION									
353 Station Equipment									
Redhawk CC Units 1 & 2		42 - R3	0	46,000,000	532,552	45,467,448	41.5	1,095,337	2.38
West Phoenix CC 4		42 - R3	0	1,953,105	121,193	1,831,912	40.5	45,199	2.31
Total Account 353				47,953,105	653,745	47,299,360		1,140,536	2.38
355 Poles and Fixtures - Steel									
Redhawk CC Units 1 & 2		55 - R3	0	1,500,000	17,032	1,482,968	54.5	27,205	1.81
356 Overhead Conductors and Devices									
Redhawk CC Units 1 & 2		55 - R3	0	1,500,000	17,834	1,482,166	54.5	27,191	1.81
TOTAL TRANSMISSION PLANT				50,953,105	688,611	50,264,494		1,194,932	
TOTAL DEPRECIABLE PLANT				714,829,252	15,580,746	699,248,506		27,590,289	
NONDEPRECIABLE PLANT									
340 Land									
Redhawk CC Common				2,246,597					
West Phoenix CC 4				32,909	70				
TOTAL NONDEPRECIABLE PLANT				2,279,507	70				
TOTAL PWE PLANT IN SERVICE				717,108,759	15,580,816				

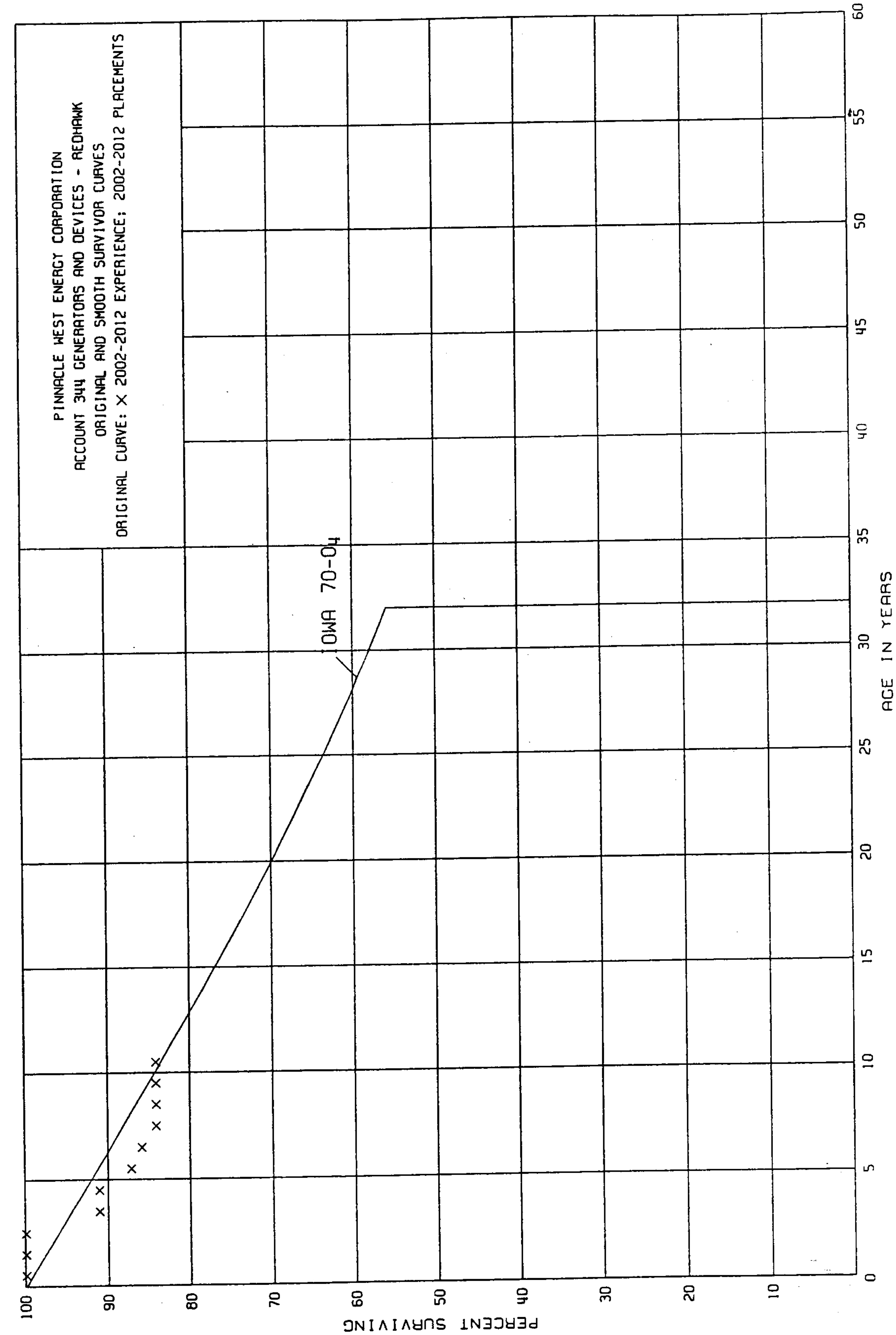
APPENDIX A

SERVICE LIFE STATISTICS


PINNACLE WEST ENERGY CORPORATION
ACCOUNT 341 STRUCTURES AND IMPROVEMENTS
SMOOTH SURVIVOR CURVE
IOWA 80-S1
AGE IN YEARS
PERCENT SURVIVING
0
10
20
30
40
50
60
70
80
90
100
110
120


PINNACLE WEST ENERGY CORPORATION
ACCOUNT 342 FUEL HOLDERS, PRODUCTS AND ACCESSORIES
SMOOTH SURVIVOR CURVE
IOWA 70-S1
PERCENT SURVIVING
AGE IN YEARS


PINNACLE WEST ENERGY CORPORATION
ACCOUNT 343 PRIME MOVERS
SMOOTH SURVIVOR CURVE
IOWA 70-L1.5
PERCENT SURVIVING
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30
35
40
45
50
55
60
AGE IN YEARS


PINNACLE WEST ENERGY CORPORATION
ACCOUNT 344 GENERATORS AND DEVICES - REDHAWK
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 2002-2012 EXPERIENCE; 2002-2012 PLACEMENTS
IOWA 70-O4
PERCENT SURVIVING
AGE IN YEARS
0
5
10
15
20
25
30
35
40
45
50
55
60
100
90
80
70
60
50
40
30
20
10

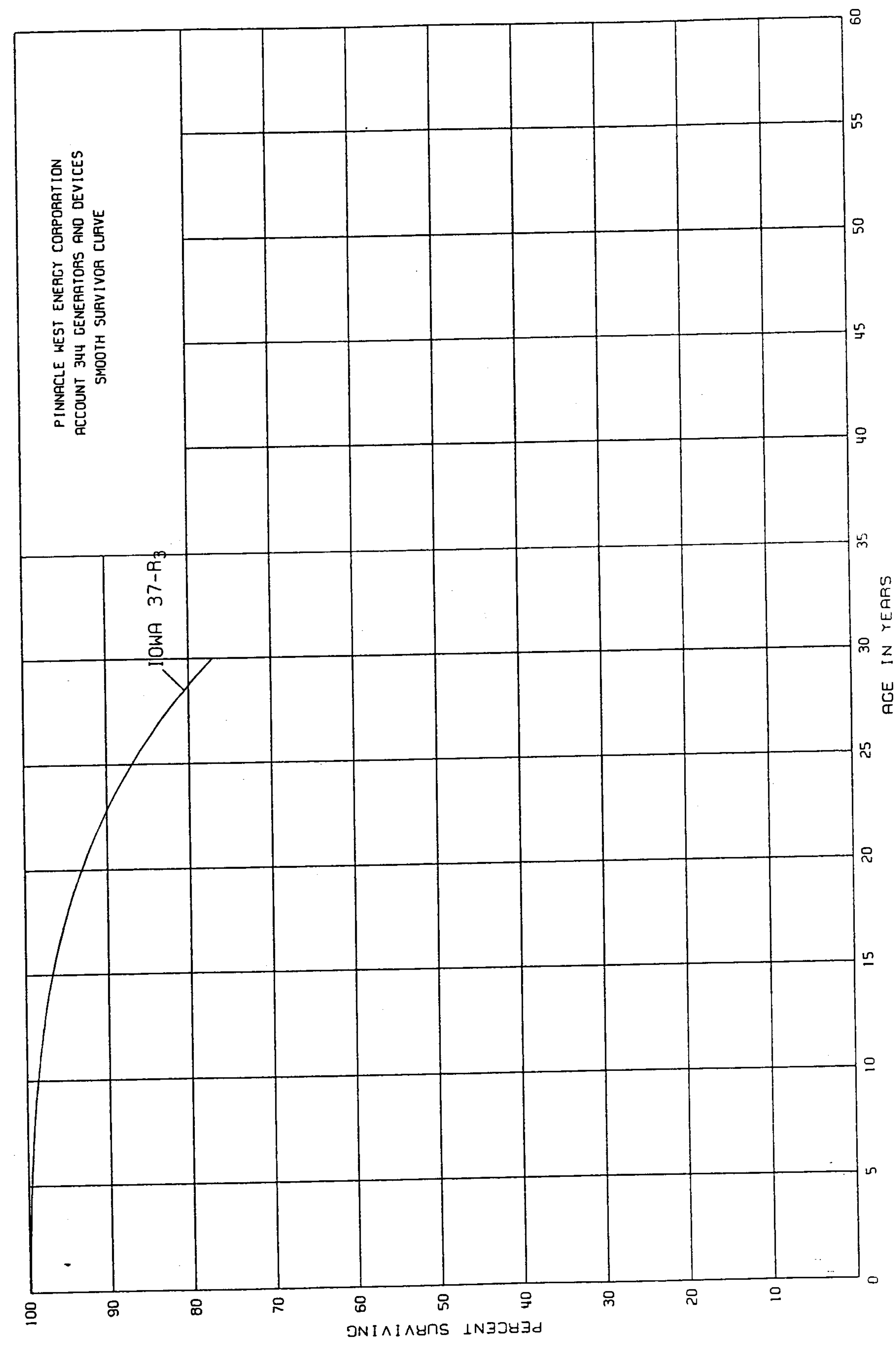
PINNACLE WEST ENERGY CORPORATION

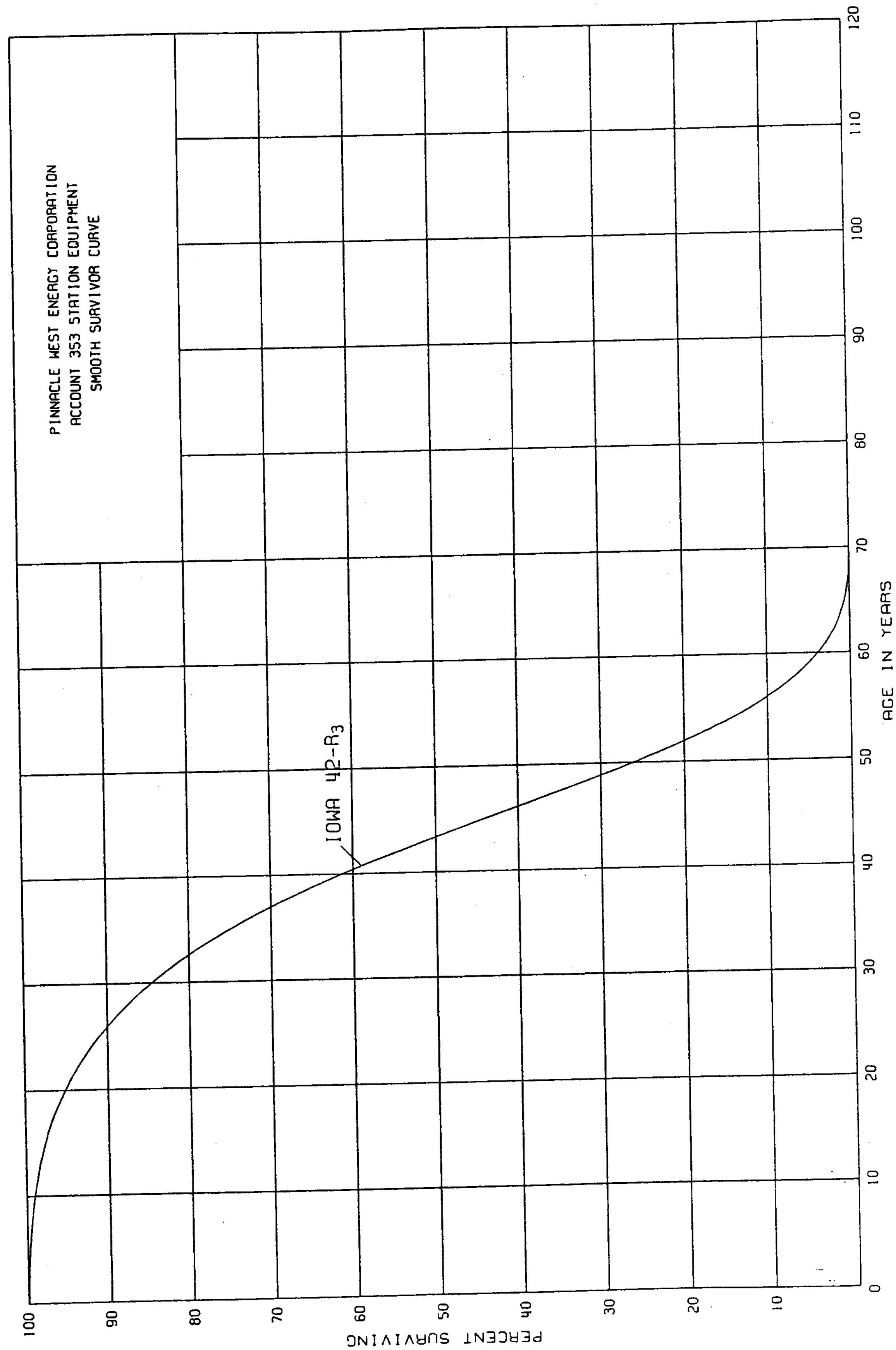
ACCOUNT 344 GENERATORS AND DEVICES - REDHAWK

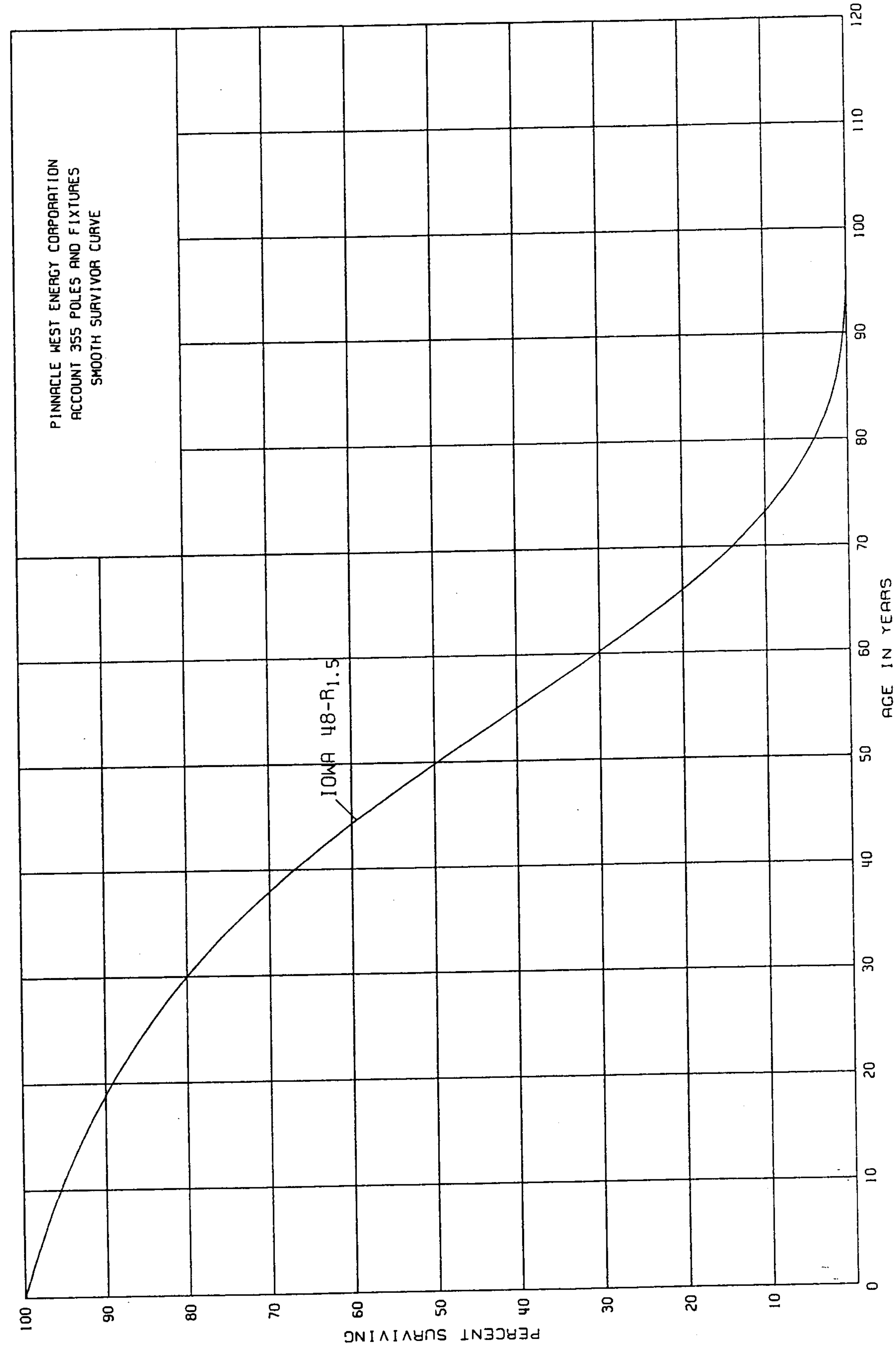
ORIGINAL LIFE TABLE

PLACEMENT BAND 2002-2012 EXPERIENCE BAND 2002-2012

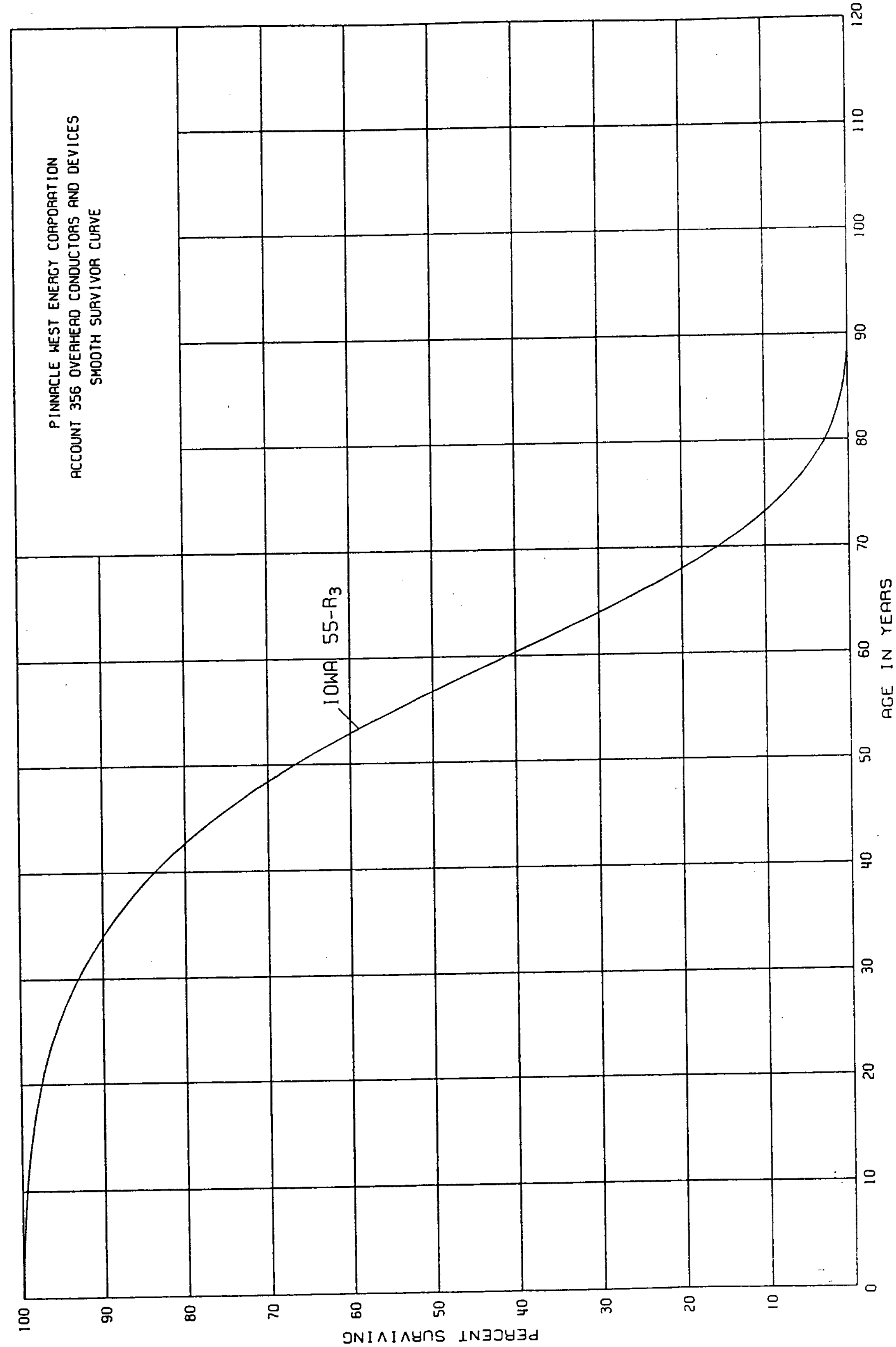
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	698,322,236		0.0000	1.0000	100.00
0.5	684,843,553		0.0000	1.0000	100.00
1.5	684,443,799		0.0000	1.0000	100.00
2.5	666,328,389	60,272,252	0.0905	0.9095	100.00
3.5	606,056,137		0.0000	1.0000	90.95
4.5	580,358,886	24,434,000	0.0421	0.9579	90.95
5.5	547,339,942	8,380,000	0.0153	0.9847	87.12
6.5	538,582,942	10,550,000	0.0196	0.9804	85.79
7.5	527,449,850		0.0000	1.0000	84.11
8.5	527,429,849		0.0000	1.0000	84.11
9.5	527,009,849		0.0000	1.0000	84.11
10.5					84.11


PINNACLE WEST ENERGY CORPORATION
ACCOUNT 344 GENERATORS AND DEVICES
SMOOTH SURVIVOR CURVE
IOWA 37-R3
AGE IN YEARS
PERCENT SURVIVING
0
5
10
15
20
25
30
35
40
45
50
55
60
100
90
80
70
60
50
40
30
20
10


PINNACLE WEST ENERGY CORPORATION
ACCOUNT 353 STATION EQUIPMENT
SMOOTH SURVIVOR CURVE
IOWA 42-R3
AGE IN YEARS
PERCENT SURVIVING
0
10
20
30
40
50
60
70
80
90
100
110
120
100
90
80
70
60
50
40
30
20
10



PINNACLE WEST ENERGY CORPORATION
ACCOUNT 355 POLES AND FIXTURES
SMOOTH SURVIVOR CURVE
IOWA 48-R1.5
AGE IN YEARS
PERCENT SURVIVING
0 10 20 30 40 50 60 70 80 90 100 110 120
100 90 80 70 60 50 40 30 20 10


PINNACLE WEST ENERGY CORPORATION
ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES
SMOOTH SURVIVOR CURVE
IOWA 55-R3
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120
PERCENT SURVIVING
100
90
80
70
60
50
40
30
20
10

APPENDIX B

DEPRECIATION CALCULATIONS

PINNACLE WEST ENERGY CORPORATION

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
WEST PHOENIX CC 4						
INTERIM SURVIVOR CURVE.. IOWA 80-S1						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. 0						
2001	3,768,898	191,460	234,108	3,534,790	28.05	126,017
	3,768,898	191,460	234,108	3,534,790		126,017
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					28.1	3.34

PINNACLE WEST ENERGY CORPORATION

ACCOUNT 342 FUEL HOLDERS, PRODUCTS AND ACCESSORIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
WEST PHOENIX CC 4 INTERIM SURVIVOR CURVE.. IOWA 70-S1 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. 0						
2001	4,135,109	211,304	257,106	3,878,003	27.86	139,196
	4,135,109	211,304	257,106	3,878,003		139,196
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					27.9	3.37

PINNACLE WEST ENERGY CORPORATION

ACCOUNT 343 PRIME MOVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
WEST PHOENIX CC 4 INTERIM SURVIVOR CURVE.. IOWA 70-L1.5 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. 0						
2001	57,116,985	2,907,255	3,545,340	53,571,645	27.58	1,942,409
	57,116,985	2,907,255	3,545,340	53,571,645		1,942,409
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					27.6	3.40

PINNACLE WEST ENERGY CORPORATION

ACCOUNT 344 GENERATORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
REDHAWK CC 1 & 2 INTERIM SURVIVOR CURVE.. IOWA 70-O4 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. 0						
2002	546,899,426	6,726,863	9,255,982	537,643,444	24.05	22,355,237
WEST PHOENIX CC 4 INTERIM SURVIVOR CURVE.. IOWA 37-R3 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. 0						
2001	14,296,553	749,139	897,926	13,398,627	26.76	500,696
SAGUARO CT 3 INTERIM SURVIVOR CURVE.. IOWA 37-R3 PROBABLE RETIREMENT YEAR.. 6-2032 NET SALVAGE PERCENT.. 0						
2002	37,659,176	655,270	701,673	36,957,503	27.75	1,331,802
	598,855,155	8,131,272	10,855,581	587,999,574		24,187,735

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 24.3 4.04

PINNACLE WEST ENERGY CORPORATION

ACCOUNT 353 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
REDHAWK CC 1 & 2 SURVIVOR CURVE.. IOWA 42-R3 NET SALVAGE PERCENT.. 0						
2002	46,000,000	538,200	532,552	45,467,448	41.51	1,095,337
WEST PHOENIX CC 4 SURVIVOR CURVE.. IOWA 42-R3 NET SALVAGE PERCENT.. 0						
2001	1,953,105	68,359	121,193	1,831,912	40.53	45,199
	47,953,105	606,559	653,745	47,299,360		1,140,536
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					41.5	2.38

PINNACLE WEST ENERGY CORPORATION

ACCOUNT 355 POLES AND FIXTURES - STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
REDHAWK CC 1 & 2 SURVIVOR CURVE.. IOWA 55-R3 NET SALVAGE PERCENT.. 0						
2002	1,500,000	13,350	17,032	1,482,968	54.51	27,205
	1,500,000	13,350	17,032	1,482,968		27,205
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					54.5	1.81

PINNACLE WEST ENERGY CORPORATION

ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2002

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
REDHAWK CC 1 & 2						
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. 0						
2002	1,500,000	13,350	17,834	1,482,166	54.51	27,191
	1,500,000	13,350	17,834	1,482,166		27,191
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					54.5	1.81

ARIZONA PUBLIC SERVICE COMPANY
Existing Amortization Rates and Projected Amortization Expense
For Test Year 2002, Also, Proposed Rates on
Assets Amortized and Transportation
and Power Operated Equipment's Depreciation Expense

Line No.	Amortization Group (a)	Description (b)	Original Cost at 12/31/02 (c)	Original Cost fully Amortized (d)	Accrual Rate (%) (e)	Projected Accrual Amt (f)	Line No.
1.	Intangibles						1.
2.	301	Organization	$73,639	$0	0.00%	$0	2.
3.	302	Franchise and Constents	883,584	24,299	4.00%	34,371	3.
4.	303L	PV Unit 2 Sale & Leaseback-Software	288,148	-	Over Life of lease	16,797	4.
5.	303	Misc Intangible-Contributed Plant	10,454,392	4,148,359	10.00%	630,603	5.
6.	303	Misc Intangible -Mexico Tie	1,005,921	-	20.00%	201,184	6.
7.	3031	Computer Software-5year life	95,319,618	38,793,537	20.00%	11,305,216	7.
8.	3032	Computer Software-10year life	94,482,296	-	10.00%	9,448,230	8.
9.		Total Intangibles	202,507,598	42,966,195		21,636,401	9.
10.	Production						10.
11.	321-325	PV Unit 2 & Common-Sale & Leaseback Leasehold Improvements	15,517,225	-	Over Life of lease	557,706	11.
12.	Land Rights						12.
13.	3303	Limited Term Land Rights-Hydro Plants	64,500	-	Over Remaining Life of Plant	12,900	13.
14.	3503	Limited Term Land Rights-Transmission Lines	16,831,520	-	Over Life of Land Right	914,756	14.
15.	3503	Limited Term Land Rights-SCE	1,968,074	-	Over Life of Land Right	128,546	15.
16.	3603	Limited Term Land Rights-Distribution Lines	725,029	-	Over Life of Land Right	38,686	16.
17.		Total Limited Term Land Rights	19,589,123	-		1,094,888	17.
18.	Distribution Plant						18.
19.	361,368,371	Distribution Plant Leased Property	435,292	179,394	Over Life of Each Lease	8,798	19.
20.	General Plant						20.
21.	390	Building Leasehold Improvement	11,160,324	-	Over Life of Each Lease	1,251,064	21.
22.	391	Office Furniture-New Proposed Amort. Rate			5.00%		22.
23.	391	Computer Hardware-New Proposed Amort. Rate			20.00%		23.
24.	391	Office Equipment- New Proposed Amort. Rate			10.00%		24.
25.	391	Capital Lease-Computer Equipment	5,940,563	-	Over Life of Each Lease	1,978,208	25.
26.	392	Capital Lease-Transportation Vehicles	19,553,408	-	Over Life of Each Lease	3,314,600	26.
27.	392	Transportation Vehicles	27,441,612	13,170,020	Depreciated by Vehicle Class	776,666	27.
28.	393	Stores Equipment- New Proposed Amort. Rate			5.00%		28.
29.	394	Tools, Shop, & Garage Equip.- New Proposed Amort. Rate			5.00%		29.
30.	395	Laboratory Equipment- New Proposed Amort. Rate			6.67%		30.
31.	396	Power Operated Equipment	27,947,651	13,683,982	Depreciated by Vehicle Class	787,053	31.
32.	397	PV Common Sale & Lease Back	245,938	-	Over Life of Lease	8,943	32.
33.	398	Miscellaneous Equipment- New Proposed Amort. Rate			5.00%		33.
34.		Total General Plant	92,289,496	26,854,002		8,116,534	34.
35.		Total	$330,338,734	$69,999,591		$31,414,327	35.

APS-6

EXHIBIT

tabbies

APS-6

admitted

DIRECT TESTIMONY OF CHARLES E. OLSON

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-___

June 27, 2003

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Direct Testimony of Charles E. Olson

ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-___)

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. Charles E. Olson, 10822 Alloway Drive, Potomac, Maryland, 20854.

Q. WHAT IS YOUR OCCUPATION?

A. I am an economist.

I. QUALIFICATIONS

Q. PLEASE OUTLINE YOUR EDUCATION AND EXPERIENCE.

A. I attended and received the following degrees from the University of Wisconsin at Madison: B.B.A. in 1964 (Senior Honors), M.S. in 1966, and Ph.D. in 1968. My doctoral dissertation analyzed the structure of the electric power industry.

I joined the University of Maryland in 1968 as an Assistant Professor and taught full-time in the College of Business and Management. I taught graduate courses in managerial economics, public utilities and transportation and undergraduate courses in public utilities and transportation.

In 1971, I was appointed Associate Professor and held that position until I left in September 1976 to join Zinder Companies, Inc. (Zinder) as Senior Economist. In December 1977, I was elected Vice President and in December 1979, I was elected Senior Vice President. In September 1980, I resigned to organize my own firm. I returned to Zinder in December 1986 as its President. In November 2000 I resigned as President of Zinder. Currently, I am a Teaching Professor at the University of Maryland, Robert H. Smith School of Business where I teach courses in economics. I am also a public utility consultant for the electric power industry.

During the past 34 years, I have authored and co-authored various papers, articles, reports and other published material. These have been published in <u>Public Utilities Fortnightly</u>, <u>Land Economics</u>, <u>Transportation Journal</u>, <u>Business Horizons</u>, and <u>Highway Research Record</u>. The Institute of Public Utilities at Michigan State University published a revised version of my thesis, which is titled "Cost Considerations for Efficient Electricity Supply." I have also contributed to two other volumes, <u>Studies in Electric Utility Regulation</u> (Ballinger Publishing Co., 1975) and <u>Regional Economic Effects of Alternative Highway Systems</u> (Ballinger Publishing Company Co., 1974).

I have given speeches, workshops and papers to many groups, both academic and business. I was a coordinator and lecturer in the American Gas Association's Annual Rate Fundamentals Course at the University of Wisconsin from 1971 to 1996. The topics I have lectured on in this course include utility pricing, utility accounting, rate level determination, cost of capital and cost of service analysis. I also have lectured at other American Gas Association short courses.

During the past 30 plus years as a consultant, I have worked on more than 400 rate and certificate cases and have presented testimony more than 300 times. I have testified before the Federal Communications Commission, the Postal Rate Commission, the Federal Energy Regulatory Commission (FERC), the Interstate Commerce Commission, the New York Energy Planning Board, the Dallas and

Beaumont City Councils and public utilities commissions in 40 states, the District of Columbia and three Canadian provinces. The cases involved electric, gas, water and telecommunications utilities. I have also testified in oil pipeline and taxi cases. My testimony covered numerous subjects including fair rate of return, rate base, revenue requirements, revenue and expense adjustments, pricing and rate design.

In addition, I have been a consultant on numerous other projects and studies including a study of the Uniform System of Accounts for telephone companies and a study of entry and fare determination policies for the taxicab industry in Washington, D.C. Working for the Development Advisory Service of Harvard University, I advised the government of Colombia on public utility rates. From 1977 to 1978, I directed a demand study for the gas distribution utilities in New York. Finally, I also directed a study on gas rate design for the Economic Regulatory Administration from 1977 to 1978.

I have also done a significant amount of community service work, testifying in a number of cases on a pro bono basis. I have presented testimony before two congressional committees. I was a member of two Federal Power Commission (FPC) National Power Survey Advisory Committees. Finally, I was Vice Chairman of the former FPC's Gas Policy Advisory Council: Transmission, Distribution and Storage-Technical Advisory Task Force-Rate Design.

Lastly, I am a member of the Transportation and Public Utilities Group of the American Economic Association and I am listed in <u>Who's Who in America</u>.

II. PURPOSE OF TESTIMONY

Q. WHAT IS YOUR ASSIGNMENT IN THIS CASE?

A. Arizona Public Service Company (APS or the Company) has requested that I conduct a study to determine the appropriate return on common equity for the Company.

III. IDENTIFICATION OF SUPPORTING ATTACHMENTS

Q. DO YOU SPONSOR AN EXHIBIT IN SUPPORT OF YOUR TESTIMONY?

A. Yes. I sponsor Attachments CEO-1 through CEO-8. These Attachments were prepared by me or under my direction and supervision.

IV. SUMMARY OF TESTIMONY

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. Yes. Based on the analyses that I have done, I recommend that APS be authorized a return on common equity capital of 11.25 to 11.75 percent. My opinion is based on discounted cash flow (DCF) studies of a group of comparable electric and combination companies and of Pinnacle West Capital Corporation (Pinnacle West), APS' parent. The results of my DCF analyses were further validated using the risk premium method. In my view, APS requires a return on common equity of between 11.25 and 11.75 percent.

V. OVERVIEW OF COST OF CAPITAL

Q. WILL YOU PLEASE EXPLAIN THE MEANING OF THE FAIR RATE OF RETURN?

A. Any business, whether regulated or unregulated, must earn enough dollars of profit to compensate present investors if new capital is to be attracted on reasonable terms and existing capital is to be retained. If capital cannot be attracted and retained on reasonable terms, a business will have difficulty providing reliable and adequate service. If such a condition persists, the firm will eventually have difficulty staying in business. The fair rate of return is a percentage figure, which, when applied to the appropriate rate base, will yield the earnings required to attract capital on reasonable terms. This amount, known as the earnings requirement, must be added to reasonable operating expenses, depreciation and taxes to determine the total revenue requirement that must be obtained from the rates charged.

Q. HOW SHOULD THE RATE OF RETURN BE DETERMINED UNDER PUBLIC UTILITY REGULATION?

A. The prevention of monopoly profits, i.e., a competitive result, suggests that the purpose of public utility regulation with respect to rate of return is to permit the regulated company to earn its cost of capital. By permitting a regulated company to earn its cost of capital, regulation should prevent inadequate earnings as well as limiting monopoly profits. Earnings levels above the cost of capital in the long-run imply excessive profits; likewise, earnings levels below the cost of capital indicate inability to attract capital on reasonable terms.

Presumably, a public utility could earn more than its cost on the majority of its projects; otherwise, there would be no reason for its being regulated. If the <u>rate level objective</u> of utility regulation is to approximate what would happen in competitive markets, then it follows that the average expected return on new investment is held to the cost of capital. This does not mean that all services should be expected to earn the cost of capital; the regulatory agency may have public policy-dictated, non-rate level objectives that call for cross-subsidy between services or classes of customers. The point is that the average expected rate of return on new investment in total should be equal to the cost of capital if the competitive norm is taken as the standard.

A rate of return based on the cost of capital approach is consistent with the guidelines set forth by the U.S. Supreme Court in the Bluefield (262 U.S. 679 [1923]) and Hope (320 U.S. 591 [1944]) cases, as affirmed by the Court in Duquesne Light Company v. Barasch, decided January 11, 1989 (98 PUR 4th 253 [1989]). Essentially these cases require that utilities be authorized returns that: (1) are comparable to alternative investment opportunities of corresponding risk, (2) permit capital attraction on reasonable terms and (3) maintain financial integrity. A rate of return based on the cost of capital of the company whose rates are at issue is consistent with these standards.

The Supreme Court did not quantify what it meant by capital attraction on reasonable terms and financial integrity. In the Hope case, financial integrity and capital attraction were not tied directly to bond ratings, common equity ratios or financial ratios. However, the financial condition of the utility was discussed. It was noted that Hope Natural Gas Company was 100 percent common equity financed and that the yields on better issues of bonds of natural gas companies were close to 3 percent. Hope had protected, established markets and an adequate gas supply. The Commission (Federal Power Commission) had concluded that Hope was in "... a strong position to attract capital upon favorable terms when it is required." The authorized return was 6.5 percent, or more than double the going rate on better gas company bond issues.

Viewed in this historical perspective, it is difficult to read the Hope case or the earlier Natural Gas Pipeline case (315 U.S. 575 [1942]) without concluding that a utility's bonds should be rated solid A or higher and its common stock should have a market-to-book ratio of at least 1:1. There are simply too many references to sound financial parameters and not even a suggestion that there might be difficulty attracting capital on reasonable terms.

Q. HOW IS THE FAIR RATE OF RETURN DETERMINED FOR A REGULATED ENTERPRISE?

A. The fair rate of return is determined through the use of the cost of capital approach. Under the cost of capital approach, separate determinations are made of the cost of each type of capital utilized by the utility. If, for example, a utility is financed with long-term debt, preferred stock and common equity, the cost of each of these components is estimated individually. Then the cost rate of each component is weighted by the appropriate percentage that it bears to the overall capitalization. The sum of the weighted cost rates is the overall cost of capital and is used as the basis of the fair rate of return.

VI. DESCRIPTION OF METHODOLOGY

Q. PLEASE EXPLAIN THE STEPS YOU FOLLOWED IN DEVELOPING YOUR RECOMMENDED RATE OF RETURN ON COMMON EQUITY CAPITAL FOR APS.

A. I began by examining the proposed capital structure. Next I developed an estimate of the return that investors would require to invest in the common stock of APS. Toward this end, I prepared a study of the cost of common equity to APS using a DCF analysis of a group of electric, as well as combination electric and gas companies. I checked the reasonableness of my DCF result for APS by also doing a DCF study of Pinnacle West, and finally by using the risk premium approach.

Q. WHAT MATERIALS DID YOU UTILIZE IN THE PREPARATION OF YOUR TESTIMONY AND EXHIBITS?

A. Most of the information I utilized was from standard financial sources, such as annual reports and financial reports. In addition, I have testified in previous APS cases. I believe that I am familiar with the economic, financial and regulatory issues that have and will have an impact on the ability of APS to attract capital in the future.

Q. WHAT CAPITAL STRUCTURE IS PROPOSED BY APS IN ITS FILING IN THIS CASE?

A. The proposed capital structure is dependent upon whether or not some $500 million of debt becomes a permanent part of the Company's capital structure, which in turn depends on whether the generation assets supported by that debt are included in APS' rate base. The capital structure as of 12/31/02 consists of approximately 50 percent long-term debt and 50 percent common equity. If the PWEC-related debt is incorporated into that capital structure, leverage is increased to 55% debt and just 45% common equity. APS has no preferred stock at this time.

Q. ARE THE CAPITAL STRUCTURE ALTERNATIVES PROPOSED BY APS REASONABLE ONES TO UTILIZE FOR RATEMAKING PURPOSES IN THIS CASE?

A. Yes, they are given the Company's assumption that the Pinnacle West Energy Corporation (PWEC) Arizona generation assets are going to be included in rate base. The overall rate of return that is applied to the rate base is the product of three variables: capital structure, embedded cost of long-term debt capital, and the appropriate return on common equity. In that the objective of ratemaking with respect to return is a reasonable "end-result," it is not appropriate to view one of the variables that impacts on the total return dollars in isolation. The common equity ratio proposed in this case is also reasonable relative to the debt ratio with which it is combined and the recommended return on common equity capital.

Ultimately, a reasonable "end-result" can only be judged in terms of whether it will permit capital attraction on reasonable terms. At the most basic level, the equity ratio must be high enough to permit additional debt capital to be issued at any time without an adverse effect on APS' credit rating. If the capital structure does not permit some margin for additional debt financing at all times, APS is subject to the potential adverse impact of unanticipated tight credit conditions.

Q. DO THE COMPANY'S TWO ALTERNATIVE CAPITAL STRUCTURES AFFECT YOUR RECOMMENDED COST OF EQUITY?

A. No. Each is consistent with its underlying fundamental assumption concerning the ratemaking treatment of the PWEC generating assets and thus, for my purposes, more or less equivalent. If APS is not permitted to acquire and rate base the PWEC assets, PWEC will have to fully repay its loan from

APS when due in early 2007. As a result, the proceeds will likely be used to pay off APS debt, thus returning APS to roughly the same capital structure ratios as in effect at the end of the 2002 test period. I say this because without those assets, APS will be correspondingly far more dependent upon the vagaries of the wholesale market for power supplies to meet its public service obligation. In addition, the financial community imputes a portion of the value of long-term power contracts onto the balance sheet as debt. Both of these factors entail more risk for APS that must be compensated for by a more conservative capital structure.

Q. PLEASE DISCUSS THE RELATIONSHIP BETWEEN CREDIT CONDITIONS AND CAPITAL STRUCTURE FOR A REGULATED UTILITY.

A. The Federal Reserve Board controls the supply of money in the United States. Because it is widely believed that there is a close relationship between growth in the money supply and inflation, the concern exists that the growth in money supply will be slowed or even halted by the Federal Reserve Board. Thus, when inflationary pressures exist, a natural policy reaction is to slow monetary growth. This in turn produces tight credit conditions, difficulty in borrowing and a depressed stock market.

Credit conditions during 1974 and 1975 provide an example of the risk associated with a low equity ratio and substantial external financing requirements. After a sharp increase in the world price of oil in early 1974, combined with a phase-out of domestic price controls, the inflation rate accelerated to the double-digit level. Public utility debt financing became very difficult to obtain, and stock prices plunged. As a result, the construction programs of many utilities had to be reduced (often at great ultimate cost to customers) and common stock had to be issued at prices well below book value, thus diluting stockholder equity.

The period between 1980 and 1982 was also characterized by difficult credit conditions. Inflation accelerated to double-digit levels in 1979, partly as a result of sharp increases in oil prices. The money supply was increasing at a rapid rate; interest rates increased significantly. The Federal Reserve Board reacted by announcing that it would act to directly control the money supply, instead of attempting to control interest rates as had been done previously. As a result, interest rates reached very high levels during the 1980 to 1982 period. The prime rate exceeded 20 percent during this period, and interest rates on utility bonds exceeded 17 percent. Credit was available but exceedingly costly.

Currently (June 2003), financial markets are affected by uncertainty relative to the Federal budget, the foreign trade deficit, monetary policy, potential inflation and the lack of economic growth. Relative to the inflation rate, the cost of credit is on the high side because of nervousness about the economic situation. Given that there has been more instability in the capital markets during the past 30 plus years than existed in the 1950's and 1960's, lower long-term debt ratios are necessary to protect bond ratings and to maintain financial flexibility. In my view, the Commission should set APS' rates at a level that provide an opportunity to attract capital without dilution of existing equity or loss of creditworthiness.

Q. PLEASE EXPLAIN THE DCF METHODOLOGY YOU WILL USE TO ESTIMATE THE RATE OF RETURN ON ORIGINAL COST COMMON EQUITY CAPITAL IN THIS CASE.

A. Equity owners share in the residual that remains from revenues after expenses, including interest, are paid. Thus, there is no contractual relationship as to required earnings between the common stockholder and the corporation. Earnings on equity can only be judged in terms of whether they produce market prices for the common shares that permit capital attraction on terms that are considered fair and reasonable.

From an investor's viewpoint, the cost of common equity of a given company is the minimum expected return which will induce him to buy stock at the going market price. Thus, the focus must be on what a reasonable <u>investor</u> – and not the analyst or the regulator-- would consider is a reasonable expected return. Similarly, it is expected returns, not just present and certainly not past returns, that are relevant. For example, if an investor will buy a stock that is selling at $20.00 per share but will not buy it at a higher price, and expects to receive $1.20 in dividends and to sell it in exactly one year at $21.20, the cost of capital is 12 percent, as shown below:

Dividend Yield = ($1.20 ÷ $20.00)	= 6%
Growth = ($21.20 ÷ $20.00)-1	= 6%
Cost of common equity (k)	= 12%

Unfortunately, the task is not this easy because we can not know directly what investors really expect when they decide to buy a given stock but must infer such expectations from the application of judgment to available market data.

In my opinion, the most reasonable way to go about estimating the cost of common equity is to utilize the DCF approach. The DCF approach to estimating the cost of equity capital is based on the logical premise that the investor is buying two things when he purchases common stock, dividends and growth. Investors in American corporations have come to expect growth in earnings and dividends per share of common stock because of a public policy that is committed to continuously increasing Gross Domestic Product (GDP). In addition, the experience of most U.S. corporations since the end of World War II has been one of increased dividends and earnings per share. The cost of equity capital using the discounted cash flow method is that discount rate which equates a given market price of a stock with the expected future flow of dividends.

The discounted cash flow method is frequently expressed as a formula in which "k", the cost of capital, is equal to D/MP (dividends divided by market price), the dividend yield, plus "g", expected growth in dividends. Thus:

$$k = D/MP + g$$

In utilizing this formula it must be assumed that "g" can not exceed "k" because that implies negative dividends. It must also be assumed that a growth rate, "g", that is mathematically equivalent to a levelized rate of growth to infinity can be estimated. Mathematically this is always true, but even if it were not, it is not important for purposes of application. This is the case because the discounting of income streams far in the future has little consequence for the present value of a security.

Implementation of the DCF approach requires the exercise of judgment concerning how investors collectively estimate a firm's "g". The real question is what affects investor expectations. Estimating investor expectations is a difficult task because of the many factors that affect capital markets in general and common stocks in particular. The current state of the economy, Federal budget uncertainty, the trade deficit, fiscal policy, expected inflation, foreign exchange rates and Federal Reserve Board policy all impact significantly on investor judgments. In addition to these factors, the appropriate return on equity for APS is governed by all of the specific factors that influence its particular situation.

Q. WHAT INFORMATION IS AVAILABLE AND USEFUL FOR PURPOSES OF MAKING A DCF ESTIMATE OF THE COST OF EQUITY CAPITAL FOR APS?

A. Investors are aware of current conditions in the economy. Significant factors include the current budget and trade deficits, concerns about higher inflation, unemployment and uncertainty regarding fiscal policy. The type of information discussed at some length below is available in detail, particularly in this age of the worldwide web. Presumably, investors utilize it, understand the state of the economy and have their own expectations about GDP growth, interest rates and other factors. These opinions influence their return expectations and thereby determine the maximum price they will pay for various types of securities. Thus, because investors take the economic situation into account in their decision-making, information concerning the economy is reflected in the prices of stocks and bonds at any given time.

Q. PLEASE EXPLAIN THE SOME OF THE ECONOMIC FACTORS THAT INVESTORS MIGHT CONSIDER IN THEIR DECISION MAKING.

A. Federal budget deficits have been high historically, and after a short period of modest surplus, are again in deficit. At the end of the federal government's 2002 fiscal year (September 30, 2002), the accumulated federal debt was somewhat above $6 trillion. Currently, a deficit is projected for future years' budgets.

In addition to the budget deficit, the nation's merchandise trade deficit has been large and growing in recent years. It has increased from $132.6 billion in 1993 to approximately $434.2 billion in 2002. Trade deficits at these levels are high enough to be of concern because of the foreign debt they create.

The U.S. unemployment rate in May 2003 was 6.1 percent. This is at or near the top of the range which most economists view as the natural or expected rate of unemployment. The natural rate of unemployment is the rate at which there is no tendency for inflation to accelerate or decelerate. With unemployment at 6.1 percent, the inflation rate will have a tendency to be stable. This seems to be the current market view. Over the past 5 years the increase in consumer prices has ranged from a low of 1.6 percent in 1998 to a high of 3.4 percent in 2000. Page 1 of Attachment CEO-1 provides a summary of changes in the Consumer Price Index ("CPI") over the last 13 years.

Real GDP decreased in 1991 at a rate of –0.5 percent. Since then the rate of increase has ranged from 0.3 to 4.4 percent. GDP data for the 1990 to 2002 period are shown on page 2 of Attachment CEO-1.

Money supply ("M2") growth in 1994 was 0.4 percent, a very low figure. However the growth rate was 4.1 percent in 1995, increasing to 10.2 percent in 2001. The

2002 growth rate was 6.3 percent. Growth data for the M2 measure of money supply are shown on Attachment CEO-1, page 3 of 4. The growth rate in money supply can impact the cost of capital because it has an influence on the inflation rate.

Q. PLEASE EXPLAIN THE RISK PREMIUM APPROACH TO ESTIMATING THE COST OF COMMON EQUITY CAPITAL.

A. The risk premium approach is based on the premise that common stocks are riskier than bonds. Consider the case of a given corporation. The bondholder has a prior claim on the assets of the company in the event of bankruptcy as well as on the earnings of the company while it is in operation. The common shareholder receives the residual earnings from operations. The bonds of a corporation are thus less risky than the common shares.

In The Stock Market: Theories and Evidence (published in 1973), Lorie and Hamilton have made the following observation at page 214:

> It is perfectly clear that bonds are less risky than stocks when both classes of securities are issued by the same corporation. Since bondholders have a prior claim to the earnings and assets of the corporation the rates of return on bonds are less variable and more confidently predicted than rates of return on the common stock. This fact is so obvious that it has not been studied and does not require study.

This same point has been made by Myers:

> Interest rates on corporate bonds and other debt instruments can be readily observed to provide a floor for the estimate.

> Changes in the basic level of interest rates normally correspond in direction to changes in the cost of equity capital. (Stewart C. Myers, Bell Journal of Economics, Spring 1972, p. 65.)

Both James Lorie and Stewart Myers are well-known and highly respected professors of finance, Lorie at the University of Chicago and Myers at MIT. Primarily because of the difficulty in selecting an appropriate time period to use to estimate an expected risk premium, this approach can produce a wide range of results. It should be used only as a check for that reason.

VII. APPLICATION OF DCF

Q. YOU HAVE EXPLAINED THAT YOU UTILIZE THE DCF APPROACH FOR PURPOSES OF DETERMINING THE RETURN ON COMMON EQUITY CAPITAL. YOU HAVE ALSO INDICATED THE KINDS OF ECONOMIC INFORMATION THAT INVESTORS CONSIDER IN ANALYZING POTENTIAL INVESTMENTS AND HOW THIS INFORMATION IS "EMBEDDED" IN SECURITY PRICES. WOULD YOU EXPLAIN HOW YOU WILL APPLY THE DCF APPROACH IN THIS CASE?

A. The rates at issue in this case are the retail rates of Arizona Public Service Company. APS is part of Pinnacle West and therefore does not have traded common shares. For this reason, a proxy or proxies of companies with market costs of common equity must be employed in DCF analysis. To estimate the cost of equity to APS, I will perform two DCF proxy analyses – one of a group of comparable electric and combination electric and gas companies and one of

Pinnacle West, the parent of APS. Pinnacle has some non-utility activities and investments. However, at this time, Pinnacle West's business is primarily that of regulated electric service, with close to 100 percent of its income derived from APS .

Q. WHAT MARKET INFORMATION IS AVAILABLE TO INVESTORS REGARDING PINNACLE WEST AND THE COMPANIES IN YOUR GROUP OF COMPARABLE DISTRIBUTORS?

A. Investors have ready access to have the following information:

(1) Market price data for common shares;

(2) Past and present dividends;

(3) Past and present earnings;

(4) Past, present and forecasted capital expenditure data;

(5) Yields on bonds and preferred stock;

(6) Short term forecasts by security analysts for earnings and dividends; and

(7) Regulatory commission rulings.

Q. HOW IS THIS INFORMATION UTILIZED BY INVESTORS?

A. It is reasonable to assume that it is utilized in investment decision-making. In all likelihood, the more recent the information, the more weight it is given. However, it is not reasonable to expect that past trends are ignored, especially if these past trends were the result of events or regulatory actions that will or reasonably could reoccur in the future. In addition to the above market information, investors are aware of statements by management and know that the companies such as APS are involved in significant regulatory proceedings.

Q. PLEASE EXPLAIN HOW YOU HAVE IMPLEMENTED THE DCF APPROACH IN YOUR ANALYSIS OF THE COMPARABLE UTILITIES.

A. Attachment CEO-2 is a listing of the six electric and combination companies other than Pinnacle West that make up my group of comparable or selected comparable companies. All of the companies have a 2002 revenue level between $1 and $15 billion. Pinnacle West's 2002 revenue was almost $3 billion. All of these companies have electric generation facilities and some have merchant generation. They are all listed as electric utilities by Value Line Investment Survey and derive the bulk of their income from electric operations.

Attachment CEO-3 presents common equity ratio data, as reported by Value Line, for the six electric and combination companies for 2002. The average common equity ratio for the group was 39.1 percent. This is below common equity ratio reported for Pinnacle West of 50.0 percent. In my view, the difference between the 50 percent common equity ratio for APS and the 39 percent for the comparables is not significant because the bond ratings of the comparables are so close to those of APS.

APS first mortgage debt is rated A-/A3. The bond ratings of the six comparable electric and combination companies are presented on Attachment CEO-4. The median rating by S & P is A-/BBB+ and by Moody's is A3. I limited my selection of comparable electric and combination companies to those with Standard and Poor's bond ratings of BBB+ to A and Moody's bond ratings of Baa1 to A2. Thus all of them are within one rating of APS' Standard and Poor's rating of A- and Moody's rating of A3. In my view, I have been conservative by using APS' first mortgage bond ratings for purposes of selecting comparable companies. There are two reasons for my conservative approach. First, APS will no longer have a mortgage after 2004 and as a result, its unsecured rating is likely to increase. Second, I would rather have a slightly less risky group of comparables than to err on the high side.

Q. WHAT IS SHOWN ON ATTACHMENT CEO-5?

A. Attachment CEO-5, shows the market-to-book ratios of the comparable companies I have selected for use in this case. Every company has a market-to-book ratio of 1.00 times or higher and the group average is 1.67 times. For the DCF model to reflect investor expectations, the authorized return on book value should recognize market-to-book ratios above 1.0 times. That is because investors would not purchase the stock if they expected it to fall in price. As shown on the bottom line of Attachment CEO-5, Pinnacle West has a market-to-book equity ratio of 1.14 times, well below the group average. This is an indication that investors do not expect APS to earn more than its cost of capital.

Q. WHAT DIVIDEND YIELD SHOULD BE UTILIZED FOR THOSE COMPANIES?

A. Attachment CEO-6 shows the dividend yields for the six selected companies for the period December 2002 through May 2003. I believe this period is long enough to smooth short-term fluctuations and short enough to avoid the use of stale data. The dividends used are at the current annual rate. The range in the dividend yields is from 4.18 to 7.67 percent and the mean is 5.92 percent. The median is 5.72 percent. Based on the information that is currently available, my view is that a yield of 5.92 percent is appropriate.

Q. WHAT GROWTH RATE IS EXPECTED BY INVESTORS FOR THE ELECTRIC COMPANIES YOU HAVE SELECTED?

A. Attachment CEO-7 presents the First Call consensus 5-year projected earnings growth rates for the group of electric and combination utilities. There are a number of organizations, such as Merrill Lynch, that provide individual estimates of expected growth, but there are two organizations that compile these estimates and publish consensus data. Zacks is one of these. The other is First Call. The average First Call consensus estimate of expected earnings growth for the comparable electric and combination companies in May 2003, as shown on Attachment CEO-7, is 5.2 percent. The median is 5.0 percent. (The projected growth rate for Pinnacle West is 5.0 percent.) The First Call growth rates are easily available to investors at Yahoo Finance, simply by clicking on Research. There is no charge for this information. It should also be noted that consensus forecasts for dividend growth are unavailable.

I have not presented any attachments that show historical growth rates. Based on past experience, I know there is substantial variation in these growth rate data for a variety of reasons and that it is difficult to draw meaningful and unbiased conclusions from these numbers. Perhaps more to the point, it is also known that financial analysts who make earnings forecasts are aware of historical growth rates. This means the historical information is reflected in these forecasts to the extent deemed relevant. Therefore, it is not necessary to use it again as a separate set of data, with the attendant judgmental input, in deriving an estimated dividend growth rate.

Q. WHAT IS YOUR CONCLUSION AS TO THE PROPER GROWTH RATE TO UTILIZE IN YOUR DCF ANALYSIS OF THE COMPARABLE COMPANIES?

A. In my view, investors expect a rate of growth between 5.00 and 5.50 percent for this group. This growth rate range brackets the average projected growth rate presented on Attachment CEO-7. When the 5.0 to 5.5 percent growth rate is added to the 5.92 percent dividend yield, and the yield adjustment factor is included, the investor return requirement is 11.07 to 11.58 percent. This calculation is developed as shown:

Yield	5.92%	5.92%
Yield Adjustment Factor, one-half the growth rate times the dividend yield	0.15%	0.16%
Expected Growth	5.00%	5.50%
Investor Required Return	11.07%	11.58%

Q. WHAT IS THE YIELD ADJUSTMENT FACTOR?

A. The yield adjustment factor is used to reflect the future payment of dividends in the next 12 months. When an investor buys common shares in a company, it is the future dividends that will be received, not past dividends. I have increased the dividend by one-half the growth rate to reflect this. I use the yield adjustment factor based on one-half the growth rate for two reasons. First, it represents a reasonable rough approximation of the expected increase in dividends during the year after a stock is purchased. Second, FERC has used it for many years and thus it has become a part of investor expectations.

Q. WHAT DO THE YIELD PLUS GROWTH DATA SHOW FOR PINNACLE WEST CAPITAL CORPORATION, THE PARENT OF APS?

A. As indicated on Attachment CEO-6, the dividend yield is 5.05 percent. This, in combination with the projected growth rate of 5.0 percent indicates a market return of approximately 10.18 percent. This includes a modest yield adjustment factor of 13 basis points, but does not include any allowance for issuance costs or for market pressure – both of which impact the final cost of equity.

VIII. VALIDATION OF DCF RESULTS

Q. PLEASE DESCRIBE YOUR RISK PREMIUM STUDY OF THE INVESTOR RETURN REQUIREMENT YOU ESTIMATED FOR APS.

A. The risk premium approach, as discussed earlier in my testimony, involves estimating how much greater is the return required by investors to invest in a firm's common stock than to invest in its bonds. There are other ways of measuring interest premiums, e.g., by reference to short-term Treasury bills. However, because the cost of equity capital is a long-term concept, it is appropriate to measure the risk premium in a case such as this using long-term company bonds, i.e., bonds with maturity dates at least 10 years in the future. The difficult question is how much of a premium over the bond yield should the stock carry. In Stocks, Bonds, Bills and Inflation: 2003 Yearbook, Roger G. Ibbotson has shown that common stocks have produced returns that average 6.0 percentage points more than corporate bonds. Ibbotson has been known as a leading expert on the development of risk premia for more than 25 years. Adding this figure to the average yield on Moody's Baa rated corporate bonds for the April – May 2003 period of 6.6 percent produces an equity return of 12.6 percent.

Bond yield data are presented at Attachment CEO-1, page 4. I use the Baa corporate bond yield data for APS because it represents the closet approximation of the cost of long-term debt to APS that is currently available on the Fed's website.

Q. WHAT IS YOUR OPINION REGARDING THE COST OF COMMON EQUITY CAPITAL USING THE RISK PREMIUM APPROACH?

A. In my view, the risk premium approach indicates that the investor return requirement to APS is 12.0 to 12.5 percent. This is a judgment based on the average risk premium of 6.0 percent over Baa rated corporate bonds, reduced to reflect a lower level of risk for APS relative to the average common stock return.

IX. RETURN ON COMMON EQUITY

Q. DOES THE COMPANY HAVE FINANCING COSTS?

A. Yes. A financing cost adjustment should be applied to the investor return requirement in order to avoid dilution on a given issue. This can be seen by using a simple example; assume that a utility has a book value of $25.00 per common share and financing costs are 5 percent of the issue price. If a return on common equity exactly equal to the investors' requirement is authorized and earned, the shares will trade at $25.00. If new shares are issued, net proceeds will be $23.75 per share ($25 times 95%); this, of course, dilutes the investment of the existing shareholders. In order to avoid dilution, the share price must be increased 5 percent; this is done by increasing the investors' required return by 5 percent.

Financing costs are relatively easy to estimate. Attachment CEO-8 presents data on financing costs for electric and combination companies for the year 2002 and 2003. As shown, financing costs for the group averaged 3.149 percent. This adjustment is not sufficient, however, to provide Pinnacle West with a reasonable probability of issuing common shares at a price above book value because of capital market fluctuations. The market-to-book ratio should be set high enough to permit equity financing with net proceeds equal to or in excess of book under most market conditions; otherwise, dilution will take place. Dilution is an indication of returns that do not adequately compensate investors for risk.

Q. IS A MARKET-TO-BOOK ADJUSTMENT APPROPRIATE EVEN IF PINNACLE WEST IS NOT PLANNING TO ISSUE COMMON SHARES?

A. Yes it is, for two reasons. First, the Hope case speaks in terms of the ability to attract capital. The fact that a utility currently does not have an immediate need for new capital does not mean that it does not need to maintain a position of being able to attract capital on reasonable terms. This is especially important if the Company is to be in a position to deal with unforeseen circumstances. Not planning to issue common stock is not the same as not issuing common stock. Of course, in the case of APS, its parent, Pinnacle West, must issue the common stock and APS should be responsible for bearing a large portion of the cost of accessing public equity markets through Pinnacle West.

Second, if a market-to-book adjustment is made only when a utility needs to go to the capital market, rational investors will figure this out and the adjustment will not produce the desired result. Suppose, for example, that a commission always used a market-to-book adjustment of 5 percent and the shares traded at 5 percent above book value. Assume that a determination was made in a new rate case that new shares would not have to be issued and no adjustment was made. The price of the shares would then go to book value. If then, in a future case, it was determined that external financing is necessary and a 5 percent market-to-book adjustment is made, it would not produce the desired effect. The reason is investors would know that the adjustment is only temporary and over the long run, the 5 percent adjustment will not be made and must therefore be compensated for (from the investors' perspective) by depressed market prices for the Firm's equity.

Q. WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND IN THIS CASE?

A. In my view, the cost of common equity should be between 11.25 to 11.75 percent. This recommendation is a judgment based on several considerations.

First, the market cost of equity is between 11.07 and 11.58 percent using a DCF analysis and 12.0 to 12.5 percent using a risk premium approach. Second, there is market pressure and market fluctuation associated with stock offerings that should be compensated for in the return on equity. A return of 11.25 to 11.75 percent is a reasonable minimum.

Q. CAN YOU GET TO A RECOMMENDED RETURN ON COMMON EQUITY CAPITAL FOR A UTILITY SUCH AS APS USING JUST A CALCULATION OR A WORKPAPER TYPE OF ANALYSIS?

A. No. There are numerous judgments involved in the process. This includes selection of methodology, implementation of methodology, choice of comparable companies and measurement of the risk premium. With respect to methodology, numerous methods are available including the DCF, earnings-price ratios, comparable earnings and CAPM. Implementation involves use of measurement period for the yield calculation, i.e., a day, a week, six weeks, six months. There are numerous possibilities for comparable companies with respect to how many electric versus combination companies and so on. The risk premium can be estimated in numerous ways. Finally, when a number is ultimately estimated, it can be adjusted up or down depending on a variety of risk factors. Estimating the return on common equity is comparable in difficulty to estimating the growth rate in GDP for the year ahead. There is no magic formula.

In this case we know that the number is above 11.07 percent before financing costs and could well be above 12.5 percent based on general market perceptions. A return of 11.25 to 11.75 percent is, in my view, a minimum range that balances the consumer desire for low rates in the short-run with the need for capital attraction in the long run.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

ARIZONA PUBLIC SERVICE COMPANY

Changes in the Consumer Price Index

Year	Percentage Change In CPI 1/
1990	6.1
1991	3.1
1992	2.9
1993	2.7
1994	2.7
1995	2.5
1996	3.3
1997	1.9
1998	1.6
1999	2.7
2000	3.4
2001	1.6
2002	2.4

1/ December to December Changes

Source: Economic Report of the President 2002, The Wall Street Journal, January 17, 2002, p. A-2

ARIZONA PUBLIC SERVICE COMPANY

<u>Changes in Real Gross Domestic Product</u>
<u>1990 - 2002</u>

Year 1/	Percentage Change In Real GDP
1990	1.8
1991	-0.5
1992	3.0
1993	2.7
1994	4.0
1995	2.7
1996	3.6
1997	4.4
1998	4.3
1999	4.1
2000	3.8
2001	0.3
2002	2.4

1/ Year over year.

Source: Economic Report of the President, 2002, page 279. Revised 1998, 1999, 2000 and 2001 information from the Bureau of Economic Analysis, 2-28-02, Table 6. More recent data from The Wall Street Journal.

ARIZONA PUBLIC SERVICE COMPANY

Changes in Money Supply (M2)
1990 - 2002

Year	Percentage Change In M2 1/
1990	3.8
1991	3.0
1992	1.6
1993	1.6
1994	0.4
1995	4.1
1996	4.7
1997	5.7
1998	8.7
1999	6.0
2000	6.1
2001	10.2
2002	6.3

1/ December to December changes

Source: Economic Report of the President, 2001, Barron's (2-11-02, p.MW49, 2-10-03, p. MW45.).

ARIZONA PUBLIC SERVICE COMPANY

Yields on Long-Term U.S. Treasury Bonds
And Corporate Bonds, 1990 – 2003 (To Date)

Year	Long-Term Treasury Bonds	Moody's Corporate Bonds Aaa	Moody's Corporate Bonds Baa
1990	8.61	9.32	10.36
1991	8.12	8.77	9.80
1992	7.67	8.14	8.98
1993	6.59	7.22	7.90
1994	7.37	7.96	8.62
1995	6.88	7.59	8.20
1996	6.71	7.37	8.05
1997	6.61	7.26	7.86
1998	5.58	6.53	7.22
1999	5.87	7.04	7.87
2000	6.93	7.50	8.36
2001	6.20	7.08	7.95
2002	5.41	6.49	7.80
2003			
January	5.07	6.17	7.35
February	4.93	5.95	7.06
March	4.90	5.89	6.95
April	4.99	5.74	6.85
May	4.61	5.22	6.38

Source: Economic Report of the President, 2001, Federal Reserve Statistical Release, January 8, 2002 February 25, 2002 and April 22, 2002. More current data taken from the Fed's website. Treasury yields after March 2002 based on a 25 year composite.

ATTACHMENT CEO-2

ARIZONA PUBLIC SERVICE COMPANY

Selected Electric and Combination Companies
2002 Operating Revenues

Company	2002 Operating Revenues (000,000)
CINergy Corporation	11,053
IDACORP	1,311
OGE Energy Corporation	3,245
PPL Corporation	5,830
Progress Energy, Inc.	8,344
Public Service Enterprise Group	10,173
Pinnacle West Capital Corporation	2,836

Source: C.A. Turner Utility Reports, June 2003

ATTACHMENT CEO-3

ARIZONA PUBLIC SERVICE COMPANY

Selected Electric and Combination Companies
2003 Common Equity Ratios

Company	Common Equity Ratio
CINergy Corporation	46.0%
IDACORP	46.5
OGE Energy Corporation	43.0
PPL Corporation	30.0
Progress Energy, Inc.	42.5
Public Service Enterprise Group	26.5
Mean	39.1%
Median	42.8%
Pinnacle West Capital Corp.	50.0%

Source: The Value Line Investment Survey, Edition 3, various dates.

ARIZONA PUBLIC SERVICE COMPANY

Selected Electric and Combination Companies
Bond Ratings

	(1)	(2)
COMPANY	**S&P**	**MOODY'S**
CINergy Corporation	BBB+	A3
IDACORP	A	A2
OGE Energy Corporation	BBB+	Baa1
PPL Corporation	A-	A3
Progress Energy, Inc.	BBB+	A3
Public Service Ent. Group	A-	A3
Medians	A-/BBB+	A3
Pinnacle West Capital Corp.	A-	A3

Source: C.A. Turner Utility Reports, June 2003.

ATTACHMENT CEO-7

ARIZONA PUBLIC SERVICE COMPANY

Selected Electric and Combination Companies
Projected Earnings Growth Rates

COMPANY Name	5 Year Mean Estimated GROWTH RATES
CINergy Corporation	4.5%
IDACORP	7.0%
OGE Energy Corporation	3.5%
PPL Corporation	5.9%
Progress Energy, Inc.	5.0%
Public Service Enterprise Group	5.0%
Mean	5.2%
Median	5.0%
Pinnacle West Capital Corporation	5.0%

Source: First Call Earnings Estimates, accessed May 27, 2003 through Yahoo Finance.

ATTACHMENT CEO-8

ARIZONA PUBLIC SERVICE COMPANY

Electric Utility Financing Costs, 2002-2003

Company	Amount ($000)	Commission in Percent
FPL Group	500,000	3.000
Xcel Energy	450,000	3.244
TXU Corporation	562,650	3.001
FPL Group	723,000	3.002
DQE	202,500	3.748
DTE Energy	237,875	3,250
TECO Energy	310,500	3.000
AEP	654,400	3.000
Ameren	294,000	3.262
PPL Corporation	442,250	3.151
Duke Energy	999,999	2.500
PSE&G	398,250	3.250
Puget Energy	207,000	3.382
MDU	100,800	3.000
TXU Corporation	450,485	3.246
Great Plains	132,000	3.750
Progress Energy	614,673	2.387
Pinnacle West Capital	206,482	3.500
AVERAGE COST		3.149%

Source: Public Utility Financing Tracker, February 2003, information provided by APS.

EXHIBIT
APS-7
admitted

DIRECT TESTIMONY OF AJIT P. BHATTI

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-___

June 27, 2003

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DIRECT TESTIMONY OF AJIT P. BHATTI
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-____)

I. INTRODUCTION AND SUMMARY

Q. WOULD YOU PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Ajit P. Bhatti. I am Vice President of Resource Planning for Arizona Public Service Company ("APS" or "Company"). My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. IS YOUR PROFESSIONAL WORK EXPERIENCE AND EDUCATIONAL BACKGROUND SET FORTH IN APPENDIX A TO YOUR TESTIMONY?

A. Yes.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AT APS.

A. As Vice President of Resource Planning, I am responsible for developing generation plans and evaluating strategic initiatives for APS.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. My testimony will describe the Pinnacle West Energy Corporation ("PWEC") Arizona generating assets that APS seeks to acquire and include in its regulated cost of service. These assets consist of the West Phoenix Combined-Cycle Units 4 and 5 ("WP-4" and "WP-5"), Redhawk Units 1 and 2 ("Redhawk-1" and "Redhawk-2"), and Saguaro Combustion Turbine Unit 3 ("Saguaro CT-3"). I will then discuss whether those assets have been, are, and will be "used and useful" in serving APS customers. I next discuss the resource planning process that planned for, designed, and evaluated the PWEC assets. Lastly, I testify concerning the actual construction of the PWEC assets that are the subject of this proceeding.

Q. WERE YOU PERSONALLY INVOLVED IN THE RESOURCE PLANNING PROCESS FOR THE COMPANY DURING BOTH THE PLANNING AND CONSTRUCTION OF PWEC'S ARIZONA GENERATING UNITS?

A. Yes. The Redhawk and West Phoenix units were planned while I was head of the Resource Planning Department at APS. These units, along with Saguaro CT-3, were constructed while I was head of the Generation Planning Department at PWEC. With the Arizona Corporation Commission's ("Commission") decision to preclude divestiture and instead preserve APS as a traditional vertically-integrated utility, I was transferred back to APS and assumed my present duties.

Q. WOULD YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY?

A. My testimony will show that:

- the PWEC assets were built to serve APS load, have done so in the past, and are doing so currently;
- the PWEC assets are "used and useful" in meeting the reliability and energy needs of APS customers both now and in the future;
- the decision to build the PWEC assets was based on a prudent and reasonable resource planning process in which the needs of APS customers, rather than the profitability of PWEC, were paramount;
- the PWEC assets were analyzed with sound economic principles and were determined to be the best generation option for our customers;
- the PWEC assets were timely constructed, and their as-built cost is reasonable compared to similar generating assets of the same vintage and as compared to alternatives available to APS.

The PWEC assets were built to keep the lights on for APS customers. They have already accomplished this purpose in 2001 through 2003. And they will continue to provide an economic and reliable source of power for APS customers for decades into the future if the Commission seizes this unique opportunity to place them into the Company's rate base at their 2004 depreciated original cost. The alternatives to the PWEC assets range from speculative to non-existent, as can be seen from the recent Track B solicitation. Market alternatives are likely to be even less viable in the future as the present glut of capacity quickly dries up and little or no new capacity is added in the Southwest.

The PWEC assets provide more than just capacity and energy, although that is clearly their primary function. They also provide APS operating flexibility, as well as critical voltage support to the APS transmission system. The PWEC assets themselves incorporate the most current environmental controls, preserve precious groundwater resources through the use of effluent for cooling, and will partially displace older, less efficient resources on the APS system, especially in the Valley.

Each of a series of APS Resource Planning decisions during the last decade conclusively demonstrates the prudence, in fact the necessity, of constructing the PWEC assets to serve APS. That period, the 1995-2000 planning horizon, which encompassed the primary planning and construction commitment period for the PWEC assets, takes on special significance. But throughout our planning activities both at APS and at PWEC, our overriding concern has always been to satisfy the traditional electric utility's essential purpose of maintaining reliability for our customers at a reasonable and stable cost.

Resource planning decisions cannot be analyzed in a vacuum, but must be understood within the historical context of their time. For the PWEC assets, it was a time characterized by unprecedented regulatory uncertainty, economic disruption on a regional and even national scale, and explosive demand growth within the APS service area and, indeed, throughout the Southwest. I have prepared a simplified timeline as Attachment AB-1 that depicts at least the major events in Arizona, the region and nation, and for APS/PWEC planning and construction so that it is possible to get a better understanding as to how all of these various pieces fit together. I would add that despite these challenges, we succeeded not only in reliably serving an expanding number of APS customers, but also protecting both them and the Company from a wholesale market gone mad. And we are now positioned to continue that record of service into the future with the strong market hedge that a balanced, fuel-diverse portfolio of utility-owned and Commission-regulated generation assets provides.

The construction of the PWEC assets was itself timely and skillfully managed to produce reasonable as-built costs for APS customers, both as compared to other generation options available to APS and as compared to reliance on wholesale purchases, when and if available. And the savings from placing these assets into the Company's rate base at their 2004 depreciated cost will provide additional value to our customers. These approximate savings have been quantified in APS witness Steven M. Wheeler's testimony as amounting to between $214 million and nearly $500 million over the estimated 30-year life of the PWEC assets.

More specifically and in support of my conclusions, my testimony, along with the testimony of Mr. Wheeler and Dr. William H. Hieronymus will demonstrate that:

- The current and projected APS reliability deficit was identified as far back as 1998;

- The conclusion that APS would have to buy or build additional capacity to meet this deficit was based on sound regional supply and demand analyses;
- APS, and later PWEC, maintained a very flexible generation expansion plan to address APS capacity needs, even at the expense of PWEC's interests, throughout the planning and construction of the PWEC units;
- The PWEC assets were planned and built to meet the growing needs of APS customers in a timely manner, were sited at locations where they were needed to serve APS load and used state of the art technology;
- All of the PWEC assets were necessary to meet APS' peak load requirements in the recent Track B solicitation;
- WP-4 and WP-5 serve Valley "must-run" requirements and provide necessary operational benefits in addition to meeting the Company's overall capacity and energy needs; and
- Cost-of-service treatment of the PWEC assets was shown by the Company's economic analyses to potentially save APS customers over $519 million (net present value over the life of the assets).

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into seven sections, as follows:

- Introduction and Summary
- The PWEC Assets
- "Used and Useful"
- APS Resource Planning
- Economic Analyses of the PWEC Assets
- Construction Activities
- Conclusion

II. THE PWEC ASSETS

Q. WHAT PWEC GENERATING ASSETS IS APS PROPOSING TO ACQUIRE AND PLACE INTO ITS REGULATED RATE BASE?

A. The PWEC generating assets at issue in this proceeding comprise five units having a capacity of approximately 1700 megawatts ("MW"). These are WP-4 and WP-5, Redhawk-1 and Redhawk-2, and Saguaro CT-3. As noted earlier, the first four of these units are combined cycle generators, while the fifth unit is a small, simple cycle combustion turbine.

Q. WOULD YOU DESCRIBE EACH OF THESE UNITS AND THEIR OPERATING HISTORY TO DATE IN MORE DETAIL?

A. Yes.

Redhawk-1 and Redhawk-2:

The Redhawk Power Plant is located approximately 50 miles west of Phoenix near the Palo Verde Nuclear Generating Station ("Palo Verde"). The Redhawk facility consists of two nominally-rated 530 MW combined cycle gas turbine generating units, for a total rated capacity of 1060 MW. Redhawk has access to the APS transmission grid via two 500-kilovolt ("kV") transmission lines from the plant to the Hassayampa switchyard. Both Redhawk-1 and Redhawk-2 use natural gas fuel, and each has two GE Frame 7FA combustion turbines in combination with a single Alstom steam turbine. And, in addition to being the latest in fossil generation technology, the units are equipped with selective catalytic reduction ("SCR") technology to comply with all requirements of the Clean Air Act's strict "best available control technology" pollution control requirements. Redhawk also uses wastewater effluent from cities in the metropolitan Phoenix area for primary cooling rather than ground or surface water.

The facility entered operation in time to meet the summer of 2002 APS peak loads. Both units have been providing their electric output to APS customers on an as-needed and economic basis since their in-service. They are now under contract to APS (along with WP-4, WP-5 and Saguaro CT-3) for the summer months through 2006 as a result of the Commission's recent Track B solicitation.

The unit equivalent availability factor ("EAF"), which is a standard industry measurement of a generating unit's reliability, was approximately 86% through May of 2003. Thus, the Redhawk units have already generated more than 4,039,251 MWH of electric energy.

WP-4 and WP-5:

These two new combined cycle units are located adjacent to APS' existing West Phoenix Power Plant site near 43rd Avenue and Buckeye Road in Phoenix. WP-4 is nominally-rated at 120 MW, whereas WP-5 is a nominally-rated 530 MW unit similar to Redhawk. WP-4 and WP-5 are connected to the Valley 230 kV transmission network system, which supports the Valley's "Reliability Must Run" ("RMR") situation during summer peak. As explained later, both new units also provide much needed overload protection and voltage support in Phoenix. Again like Redhawk, the facility burns natural gas fuel. PWEC further paid the cost of equipping APS' existing West Phoenix Unit 3 with SCR to further reduce emissions from the site.

WP-4 was placed in service on June 1, 2001 and was essential in meeting APS' load in that year. Since then, WP-4's output has been continuously serving APS customer capacity and energy needs. A review of the historical operating log indicates that WP-4 generated some 1,115,344 MWH of energy in 2001, 2002 and

2003 (through May). Virtually all of this energy was used by APS to displace less efficient and/or more costly resources. WP-4's EAF was 94.3%, 95.4% and 97.6 % during this same time period, which is far above the industry average for such units.

WP-5 is estimated to be in commercial operation by July 2003. However, test energy has been available to APS from WP-5 since March 15, 2003 on an economic basis, and WP-5 can provide over 300 MW of capacity from its already completed simple cycle turbine.

Saguaro CT-3:

Saguaro CT-3 is located adjacent to APS' existing Saguaro power plant site near Red Rock, Arizona, which is approximately 30 miles north of Tucson. This simple cycle, natural gas fired combustion turbine is 80 MW in size and is used for APS peaking needs. Since Saguaro CT-3's commercial operation date of June 2002, the unit has provided 66,515 MWH of energy through May 31, 2003. Saguaro CT-3 has directly displaced either less efficient generation or more costly market purchases by APS during that period. Its EAF through May of 2003 has been over 98%.

III. <u>"USED AND USEFUL"</u>

Q. WHAT IS YOUR UNDERSTANDING OF THE CRITERIA FOR A PLANT TO BE CONSIDERED "USED AND USEFUL"?

A. My understanding of the criteria to be considered in determining if a plant is "used and useful" is fairly straightforward. If there is a functional need for the plant's output, then the plant meets the criteria for being used and useful. This was the test used by the Commission when determining whether or not to include Palo Verde in the Company's rate base and, I am told, all of the rest of the APS facilities previously incorporated into its rate base.

Q. ARE THE PWEC UNITS "USED AND USEFUL"?

A. Yes. My testimony has already detailed both how APS has received and is presently receiving power from these generating plants. And that power has been, is, and will be necessary to serve APS customers. During 2002, PWEC provided nearly 20% of the total capacity used to serve APS load. Although the Valley reliability contribution by the PWEC units (15.4%) was somewhat less than their overall contribution to APS needs, there were no practical alternatives to WP-4. And for 2003, the PWEC contribution will be higher with the addition of WP-5. Looking into the near future, estimated APS retail load plus a modest reserve requirement of 15% (some of the merchant power plant intervenors in the recent Track B proceeding argued for a higher reserve margin of at least 17-18%) for 2004 is 6810 MW. Even counting all of the recent Track B acquisitions of power and including all of the PWEC generation sought to be included in the Company's rate base, APS will need yet additional generation resources before this rate filing is decided. Thus, its reserve margin will not be "razor thin," as characterized by the Commission in the case of Palo Verde, but nonexistent. And, again including the PWEC assets, the deficit grows in future years, reaching at least 1130 MW by 2007, the year following the end of the present contract between APS and PWEC covering these generating facilities. Table 1 below provides the APS system Loads and Resources ("L&R") calculation for the years 2003 through 2007. A more detailed portrayal of the full L&R calculation for these years, as well as through 2012, is on Attachment AB-2. Please note that the larger potential deficit shown on Attachment AB-2 (1557 MW) is dependent upon whether or not Salt River Project

("SRP") continues its present long-term contract with the Company, a contingency I discuss later in my testimony.

TABLE 1

APS Summer Supply & Demand Balance
Includes Track B Purchases

	2003	2004	2005	2006	2007
A. TOTAL LOAD REQUIREMENTS	6,448	6,810	7,092	7,382	7,685
B. EXISTING GENERATION	3,927	3,953	3,948	3,975	3,975
C. EXISTING CONTRACTS	830	837	844	852	860
D. ADDITIONAL NEEDS (B+C-A)	(1,691)	(2,021)	(2,300)	(2,555)	(2,850)
E. NEW RESOURCES					
PWEC	1,700	1,700	1,700	1,700	1,700
PPL's SUNDANCE PURCHASES	112	150	150		
SHORT-TERM PURCHASES	125	0	0	0	0
F. TOTAL RESOURCES OVER / (UNDER)	250	(161)	(432)	(837)	(1,130)

Q. **IS THE "USED AND USEFUL" CASE ALSO COMPELLING IF YOU EVALUATE EACH OF THE PWEC ASSETS INDIVIDUALLY?**

A. Yes, although APS does not propose to acquire the units on a piecemeal basis. Each of the PWEC assets provides a unique contribution to meeting APS customer needs

Q. **PLEASE EXPLAIN.**

A. I will begin with WP-4 and WP-5. As I mentioned in my description of these units, they provide support for the Company's RMR requirements in the Valley, where the great majority of the Company's customers reside, as well as contribute toward needed generation capacity for the entire APS system.

Q. BEFORE GOING FURTHER, COULD YOU EXPLAIN WHAT RMR MEANS?

A. RMR refers to the need for generation within a "load pocket," to operate at certain times of the year for reliability reasons because of the inability to import that marginally more economic generation into the load pocket. More specifically, a "load pocket" (sometimes also referred to as a "transmission constrained" or "import constrained" area) occurs when all the local demand within the load pocket cannot be served by importing power, thus requiring the use of some local generation. During certain hours of the year, the Phoenix area (i.e., the Valley) is such a transmission-constrained area. It consists of an integrated transmission and sub-transmission network serving both APS and SRP load, as well as the generating resources of these respective utilities within the Valley.

Q. ARE LOAD POCKETS A NEW PHENOMENON OR EVIDENCE OF INADEQUATE TRANSMISSION FACILITIES?

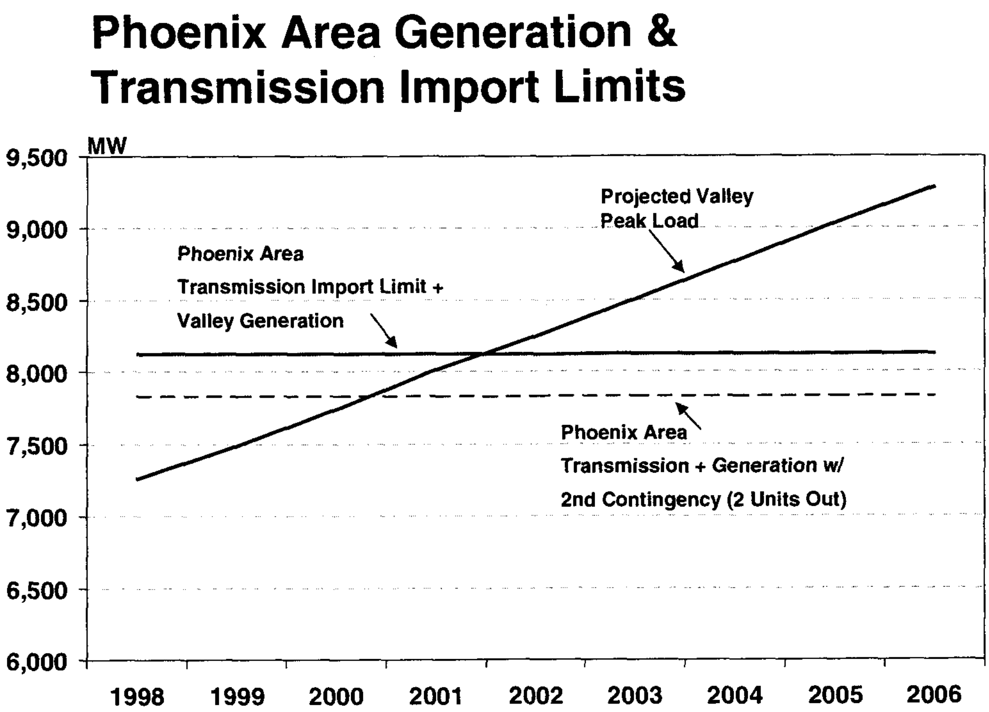
A. Neither is the case. Load pockets generally exist wherever there is concentrated load and are as old as the electric industry itself. Similarly, it is almost universally more cost effective to build local generation than to build enough transmission capacity to squeeze out the relatively few hours a year a load pocket is constrained, even assuming it were easier to site transmission than generation in an urban area. This is even more the case when the local generation was constructed years ago and is now largely depreciated.

Local generation also provides necessary voltage support, regulation, and overload protection. By voltage support, I mean that local generation allows APS to keep voltage from collapsing in the Valley in much the same way booster pumps for a gas pipeline or water system are necessary to maintain the pressure needed to operate those utility systems. A loss of voltage support could not only bring down the APS system within the Valley, it could cause severe damage to both customer and utility equipment. But unlike booster pumps, which merely pressurize whatever existing commodity is put in them, local generation also produces additional capacity and energy. By doing so, it "unloads" the strain on transmission lines into the load pocket, thus both protecting those lines from overload and permitting additional imports over them. "Regulation" is the ability to prevent wide fluctuations in voltage that can have some of the same harmful impacts as a voltage collapse. Voltage support, regulation, and overload protection are critical during peak times and beneficial all the time, even during non-constrained times of the year, and would be necessary even if no transmission (import) constraint existed.

Q. HOW DOES THE VALLEY RMR REQUIREMENT RELATE TO THE CONSTRUCTION OF WP-4 AND WP-5?

A. APS has continuously reviewed the Valley's load requirements and transmission import capabilities. An RMR study was prepared in 1997 to determine the need for future must-run generation in the Valley in conjunction with the Company's overall generation supply needs. Although the 1997 RMR study (and even later studies in 1998 and 1999) underestimated both the urgency and magnitude of the growing RMR situation in Phoenix, Figure 1 was prepared from the data available at the time and shows the Valley Loads and Resources projection for the ten-year period. As can be seen, a substantial amount of additional capacity was required within the Phoenix area to reliably serve APS customers beginning as early as 2001.

FIGURE 1



Q. HAS THE COMPANY RECENTLY BEEN ASKED TO CONDUCT A NEW RMR STUDY?

A. Yes. The Company completed another RMR study in early 2003. That study was done in conjunction with Commission Staff and at Staff's urging.

Q. DOES THIS RECENT RMR STUDY OF THE PHOENIX AREA SUPPORT THE CONTINUED NEED FOR WP-4 AND WP-5?

A. Yes, most definitely. The 2003 RMR study assumed that all of the substantial improvements to the Phoenix-area transmission system were completed and available beginning in the summer of 2003. These improvements include, most significantly, a new 500 kV line from Palo Verde to the Rudd substation, which increases the import capability into the Phoenix area by 1200 MW (APS' share is 50%, or 600 MW). A number of other transmission facility upgrades and additions were factored into the RMR study, including projects planned for 2004 and 2005. Despite these enhancements, the study specifically concluded that APS would require within the Valley an additional 365 MW in 2003, 486 MW in 2004 and 554 MW 2005. This capacity would be in addition to the 660 MW APS already owns at West Phoenix and Ocotillo.

Q. HOW COULD APS MEET THIS RMR NEED FOR THE VALLEY?

A. As the study itself concludes, additional APS transmission to relieve the RMR situation is neither economic nor desirable for operational reasons. Thus, these additional resources would need to be obtained from uncommitted SRP generation (if any) located within the Phoenix area, from more remote generation delivered over uncommitted SRP transmission capacity (if any), by newly constructed local generation, or by the already-built PWEC resources of WP-4 and WP-5.

Looking at each of these options, it is clear that building new non-PWEC generation is not an option even for 2004 and 2005. And no non-PWEC RMR bids for Phoenix covering any years after 2005 were even submitted by merchant generators in the Track B proceeding. The option of purchasing any uncommitted generation or transmission capacity from SRP is technically feasible but is an unlikely and impractical option. Although SRP and APS are obligated to and always have cooperated in a crisis situation, it appears doubtful that SRP would enter into significant firm transmission or generation contracts when it is planning to build an additional 825 MW of generation within the Phoenix constraint to meet its own needs. This was confirmed by the fact that SRP did not submit an RMR bid in the recent Track B proceeding even though it would have been bidding against APS' older and less efficient Ocotillo and West Phoenix units with PWEC as its only meaningful competitor. In that regard, I must also note that our existing long-term agreement with SRP, the so called "Territorial and Contingent" ("T&C") agreement may be cancelled by SRP beginning December 31, 2006 with three year's notice to APS. Although not itself an RMR resource, the T&C agreement's expiration would increase APS' unmet needs, as shown in my Attachment AB-2, by approximately another 400 MW beginning in 2007 (which is after expiration of the present PWEC contract with APS). And even if remote generation could be imported over SRP lines, such generation would not provide the same operational benefits, such as voltage support, as would local generation. Thus, for all practical purposes, APS has no viable alternative to WP-4 and WP-5, both of which are needed to maintain reliability in the Phoenix area.

Q. WHY DID YOU SELECT THE SITE ADJACENT TO THE EXISTING WEST PHOENIX POWER PLANT FOR NEW IN-VALLEY GENERATION?

A. We began a series of studies in 1998 that led to the final decision in April 1999 to build WP-4 and WP-5. We focused primarily on the West Phoenix facility because APS or an affiliate already owned the site and its surrounding land, PWEC could use existing infrastructure, and it was believed that we could obtain the necessary permits to build additional capacity. We also knew we could readily upgrade the transmission system around the plant to get the power onto the unconstrained side of the Phoenix-area network. In the Spring of 1999, there were no planned merchant plants within the Phoenix constraint, and even today, there are no new units planned except those built by SRP and PWEC.

Q. ARE REDHAWK 1 AND 2 OR SAGUARO CT-3 RMR UNITS?

A. No. They are not within the Valley "load pocket."

Q. THEN WHY WERE THEY CONSTRUCTED?

A. Saguaro CT-3 was a viable economic option for our 2000 - 2002 reliability program during the California energy crisis and also made sense in view of the dearth of peaking capacity being constructed by merchant generators in the region. This decision was made possible because of equipment availability on an expedited schedule and was an obvious bargain compared to paying the continued high cost of temporary generation such as PWEC had to bring on-line in 2001 to serve APS customer load growth pending completion of Redhawk and WP-5. Indeed, the cost of retaining temporary generation just for 2002 would have equaled nearly half the cost of building a thirty-year asset in the form of Saguaro CT-3.

We decided to build the Redhawk units because our planning analyses indicated a critical need for new capacity in Arizona and the Southwest that was not then being met in any other way, either through new construction in Arizona or additional imports of power into the region. Indeed, each of these units, along with the West Phoenix RMR units, were to eliminate the overall generation deficit identified via our planning studies in 1998-99 to serve our customers' demand growth in Arizona.

The construction of the Redhawk units near Palo Verde was a result of a very detailed evaluation of market conditions during its planning stages in 1998-99, as well as a thorough consideration of the existing and projected transmission network in Arizona. We also considered gas supply, water supply, and most importantly, APS customer and load growth.

Specifically, in mid to late 1998, we prepared numerous planning studies related to market supply and demand in the Southwest and Western Electricity Coordinating Council ("WECC") region. We made an assessment of merchant generators' activities, simulated the economics of new combined-cycle and simple-cycle units at various locations in the WECC, and reviewed various potential sites in Arizona for possible generation locations. All of these analyses were done in conjunction with the expertise and knowledge gained from our previous ongoing planning process and related studies, which I again address in the Resource Planning section of my testimony. Based on all this and other parallel resource acquisition strategies contemplated at that time, we developed a flexible schedule calling for 1500 to 2000 MW of new generation near the Palo Verde hub. This location would allow this new generation to both serve APS load and access the market for off-system sales during periods when it was not needed by APS. Our original plans called for newly built generation in the 2003 to 2007 timeframe, with the potential for further variations of that schedule. When it became clear that, for a variety of reasons I discuss later, we would not be able to purchase any additional generation capacity from existing jointly-owned power stations and the wholesale market appeared in total disarray, we accelerated our construction schedule. This decision eventually brought Redhawk-1 and Redhawk-2 on line in 2002, which was when they were needed by APS but somewhat before our studies showed they would be the most profitable for PWEC.

Q. ARE YOU SAYING THAT ALL OF THE PWEC GENERATING ASSETS WERE CONSTRUCTED PRIMARILY TO SERVE APS LOAD?

A. Absolutely. Since late 1998, Redhawk and West Phoenix have been a part of the APS resource plan. The schedule for their construction varied with load projections and with the potential availability of non-build resource options such as the acquisition of additional shares of Palo Verde and Four Corners Power Plant ("Four Corners"), discussed later in my testimony. But the purpose for their eventual construction was clear throughout. PWEC generation growth has always been inexorably linked to APS needs rather than the interests of a pure merchant generator.

Q. DO YOU HAVE ADDITIONAL EVIDENCE TO SUPPORT THIS ASSERTION THAT THE PWEC ASSETS HAVE BEEN DEDICATED TO SERVE APS?

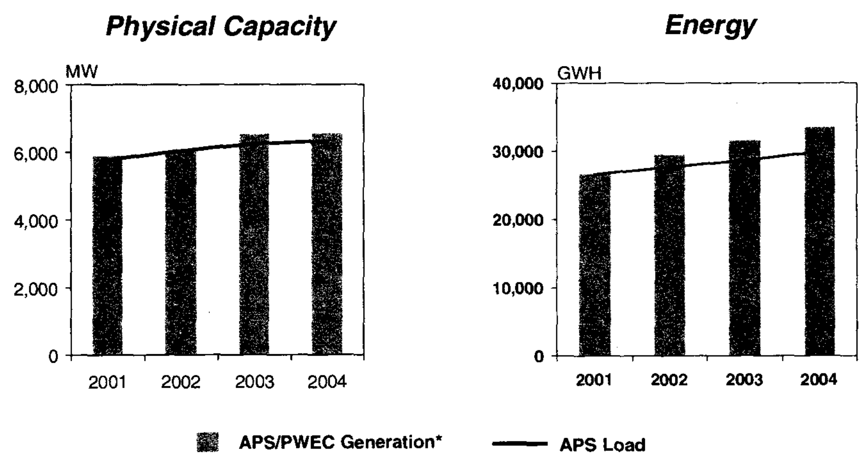
A. Yes. The location of the units also demonstrates that they were built with APS customers in mind. If we had been building these units as a pure "merchant generator," we would have chosen to build them in or closer to California. We produced numerous studies indicating that a higher potential profit could be achieved by locating a plant in or close to California than in central Arizona. But we chose to stay close to our native load because we were building the PWEC units with the goal of first serving APS customers. And unlike some of the other plants built near Palo Verde, Redhawk was specifically planned to coincide with APS' publicly-announced transmission upgrades—not west to California, but east to the Valley—that would allow that facility adequate access to APS load.

Even though our planning studies suggested a significant financial gain for Pinnacle West, in general, and PWEC, in particular, by selling PWEC's generation forward to California, Pinnacle West management decided to forego those opportunities. Thus, the marketing of power from the PWEC units, or rather, the clear decision by PWEC <u>not</u> to market power from those units also indicated that we were reserving this capacity first and foremost to meet APS load. This was at the time when California prices were at their highest and that state's Department of Water Resources was scrambling to sign contracts at very high prices in early 2001. And when it appeared that the California market debacle was spreading to other Western states, APS and PWEC developed a proposed purchase power agreement that would have assured a stable price and supply for APS customers using both APS existing generation and the PWEC units. This was done even though it precluded PWEC from earning above-cost returns over the life of the PWEC assets. These were not the actions of a merchant generator answerable only to its shareholders but the sober planning of a responsible utility attempting to discharge its public service obligation.

Finally, I have included as Figure 2 a copy of a graph from our presentation to ratings agencies on behalf of PWEC in early 2001. This was again when the opportunities in California and elsewhere in the West were very profitable. And yet the graph provided at the time shows without question that the PWEC generation would only market whatever capacity and energy that was not needed by APS, which always had first call on all of PWEC's resources.

FIGURE 2

PWEC - Generation Growing In Pace with APS Load



- Adequate capacity designed to meet APS' growing needs
- Power Marketing sales of surplus generation to other markets enhance profit margins during Q1, Q2, Q4

*Includes spot and long-term contracts

Q. SINCE NEITHER REDHAWK NOR SAGUARO ARE RMR UNITS, COULD THE COMMISSION NONETHELESS IGNORE REDHAWK AND SAGUARO AND REQUIRE APS TO ACQUIRE ADDITIONAL PURCHASED POWER TO COVER THE GENERATION SUPPLY DEFICIT STILL REMAINING AFTER CONSIDERATION OF WP-4 AND WP-5?

A. No. To do so would ignore the history as to why these units were built and the prudence of the resource planning that led to those decisions. It would also be inequitable for the reasons discussed by APS witness Steve Wheeler in his direct testimony.

With those caveats, let me also say that I have very significant doubts about both the availability and price of the well over 1000 MW of additional purchased power that such a Commission action would necessitate. You have to remember that without the PWEC assets sought to be included in APS rate base, and most specifically Redhawk-1, Redhawk-2 and Saguaro CT-3, the Company could not have met its overall reliability needs, as determined by the Commission in Track B, for even 2003. (*See* Attachment AB-3.) And as we go out a few years, the lack of interested merchant generators in committing to APS was even more evident. They, like our own forecasts, apparently see a turnaround in today's soft market in the not too distant future and likely do not want to commit resources today that will be much more valuable in a few years. Redhawk and Saguaro CT-3 provide asset-backed hedges against this market uncertainty and will generate off-system sales margins that will be especially beneficial to APS customers during periods of rising market prices, thus increasing their value in the future.

Q. WILL THE REGIONAL DEMAND/SUPPLY BALANCE IMPROVE IN THE YEARS FOLLOWING COMPLETION OF THE PRESENT RATE PROCEEDING SUCH THAT THE COMMISSION CAN SAFELY RELY ON FUTURE "TRACK B-TYPE" SOLICITATIONS TO MEET APS CUSTOMER NEEDS?

A. No. Although more new merchant generation has been or is in the process of being constructed in Arizona than could have been anticipated in late 1998 and throughout 1999, Arizona is a growing state and the Southwest a growing region. Electricity demand growth calls for over 600 MW per year of new generation needs in Arizona alone for several years to come. Yet, no new generation has been announced recently in Arizona. Depending on how fast the region and especially California recover from the recent economic slow down, the new generation currently built by others in Arizona likely will be absorbed by the projected demand growth within the next two to three years. This, in turn, would lead to a potential shortage and significantly higher prices by 2006, if not sooner. I have provided below in Figure 3 a graphic representation of the combined Arizona estimated loads and resource balance from 2003 through 2012. Dr. Hieronymus also testifies in this regard and has described a generation "boom and bust" analysis from which he postulates the next generation supply shortfall and corresponding price shock at around the same 2006-07 period.

FIGURE 3

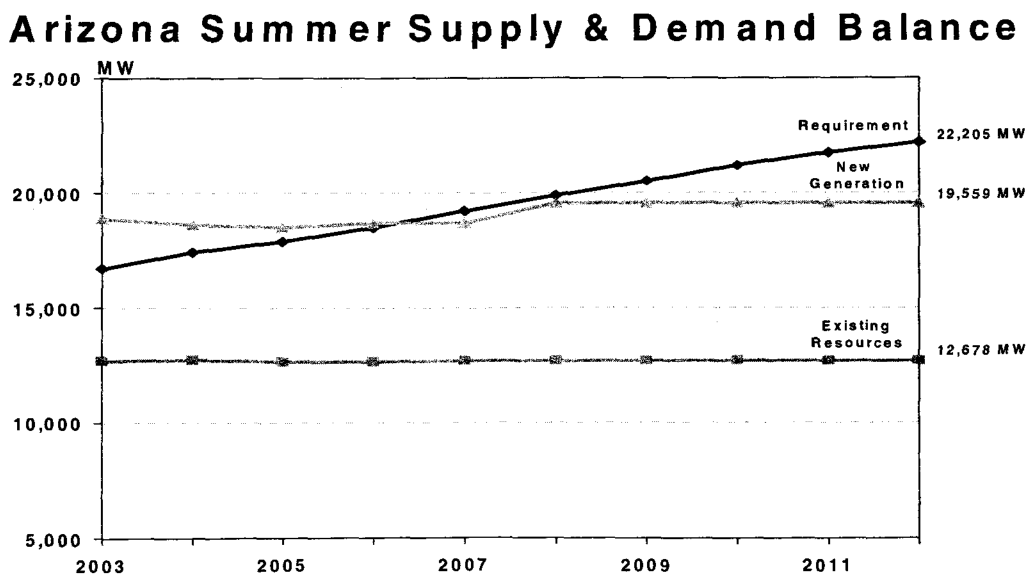


Figure 3, which depicts the Arizona generation requirement, uses demand forecasts recently provided by Western utilities to the WECC, formerly called the Western Systems Coordinating Council ("WSCC"), plus an estimated 15% reserve margin, which is the same margin APS uses in its individual studies. The existing generation includes all the generation owned by Arizona utilities, including their allocation of hydro-electric resources and outside purchased power contracts. It also assumes all the new generation presently under construction in Arizona is completed by 2004 and that SRP's Santan plant (825 MW) will be completed by 2008. We currently estimate that approximately 2800 MW of this new generation has been or will be sold to out-of-state utilities by their merchant generator owners. With these assumptions, it is estimated Arizona will require more than 2600 MW of additional new generation over the next ten years even with all of PWEC's Arizona generation and the new SRP generation. If Tucson Electric Power ("TEP") goes forward with its planned expansion of Springerville, that would improve the overall Arizona situation by about 500 MW, assuming none of that additional capacity is sent to out-of-state buyers.

Q. ASIDE FROM THE NEED FOR THE PWEC ASSETS IN SERVING APS PEAK LOAD, IS THERE ADDITIONAL EVIDENCE THAT SUCH ASSETS WOULD BE "USED AND USEFUL" IF ACQUIRED BY APS AND DEDICATED TO SERVING APS CUSTOMERS?

A. Yes. These assets fit well into the APS dispatch model. The energy produced from these units is more economical than existing APS gas and oil units, and some of the Company's purchased power contracts. Typically, the new units are dispatched after the existing APS coal and nuclear units but before the existing APS gas and oil units. This was no mere coincidence. The PWEC units were designed to fill a specific duty role in the combined APS/PWEC dispatch cycle used to serve APS customers in the most economically efficient and reliable fashion possible.

Second, the combined cycle technology used for most of the PWEC assets also provides a versatile generation base in that it can operate in discrete phases. That means there will be very few instances when the whole plant is rendered unusable for serving APS customers. The ability to function either as a base load plant, a cycling unit, or even a peaking plant gives the owner of these assets both flexibility and reliability.

Third, from a capacity mix perspective, the PWEC assets fit well with APS' existing generation. The existing generation capacity owned by APS is 28% nuclear, 43% coal, and 29% oil and gas. The coal and nuclear capacity for the APS system is operated primarily as base-load duty cycle, which means that it is operated for customers whenever it's available. In contrast, the existing gas and oil units normally operate as peaking duty cycle generators and are operated only during heavy customer demand periods. With the PWEC assets, these percentages are more balanced. The combined APS and PWEC generation capacity will be 20% nuclear, 30% coal, and 50% natural gas and oil.

Finally, from the energy production perspective, the PWEC assets also improve our historical reliance on base-load coal and nuclear energy significantly. The energy mix of APS' existing units typically has been 38% nuclear, 55% coal and 7% oil and gas. With the PWEC assets, these percentages are more balanced. The energy output from these units in 2004, for example, will be 31% nuclear, 44% coal, and 25% gas and oil. The wisdom of not relying too heavily on any one fuel has been proven many times, but it is a lesson that can be overlooked because of the overriding preoccupation with natural gas in today's market. While all of the incremental capacity built by PWEC is fueled by natural gas, our planning assumptions had always been that we would combine the natural gas-fired units with the existing APS coal and nuclear capacity to create this more-balanced portfolio.

IV. THE DECISION TO BUILD THE PWEC ARIZONA ASSETS WAS BASED ON A PRUDENT AND REASONABLE RESOURCE PLANNING PROCESS

A. APS Planning Goals, Criteria and Process

Q. WHAT ARE THE GOALS OF APS RESOURCE PLANNING?

A. The primary goals of APS Resource Planning are to provide our customers with an adequate supply of reliable power at a reasonable cost and at a reasonable level of risk. In this context, the term "reasonable level of risk" means that there must be a very high probability that the supply of power for our customers will be adequate, will be reliable, and will be at a reasonable cost. APS customers want the lights to go on and the machinery to work when they throw the switch. They are neither merchant generators nor energy speculators, and they do not want to be responsible, or have their local utility make them responsible, for the risks of such enterprises.

Q. WHAT ARE THE PRINCIPAL MEANS OF ACHIEVING THIS GOAL?

A. First, we strive to produce a flexible plan that can be adapted to fit changing circumstances. Predicting the future is always a matter of estimating probabilities, not measuring certainties. Market forces, economic trends, technological change and regulatory forces, all of which are beyond our control, can and do impact events in often unanticipated and even counter-intuitive ways. Thus, we develop scenarios for a whole range of possibilities. When new circumstances occur, as they inevitably do, we want to be ready with alternatives, whether they be modifications of one kind or another to our already existing plans or whole new approaches. This business mindset has been a key corporate strategy of APS and its parent, Pinnacle West, throughout the years-long process of electric industry restructuring in this country and in Arizona.

Second, we build our plans around our existing and proven portfolio of generation resources. APS has relied heavily since the 1970s on base-loaded coal and nuclear capacity. All of our plans began with long-range forecasts for those base-load units, as augmented by existing long-term purchased power contracts.

Third, and again building on the excellent performance of our base-load generation, we strive for a flexible and diverse fuel mix. Relying too heavily on any one fuel can expose the company and its customers to unacceptable and unnecessary supply, price and regulatory risks.

Fourth, we seek to create a diverse portfolio of generating assets in terms of size and location of the individual units. Ideally, we would not wish to depend on any single generating unit for a large percentage of our capacity. Although siting availability and system operating limits impact the location of plants, we also look for resources in different geographic areas relative to APS load centers that can potentially supply our customers over a variety of transmission links. This provides both economic and reliability benefits for APS customers.

Fifth, we are constantly seeking to improve our load forecasting expertise to identify and incorporate the most predictive data for generation planning and to better refine our generation and system modeling capabilities. In doing so, we factor in the anticipated impact of known demand-side management ("DSM") and energy reduction programs. We also estimate the impact in the aggregate of demand/energy responses to price.

Q. WHAT CRITERIA DO YOU USE TO MEASURE THESE GOALS?

A. The criteria include measurements of reserve margin, "busbar" costs (total cost per kWh of generation at the "bus," or where the generator is interconnected to the transmission system), studies of the long-term cost of various alternatives, and the impact of all three on long-term APS revenue requirements. We also try to keep the risk to customers as low as possible. We do this by establishing resource diversity targets (which I have discussed above in the context of fuel source, unit location, and unit type and size) and by combining a solid foundation of owned resources with a mix of long and short-term market purchases.

Q. WILL YOU PLEASE DESCRIBE THE APS RESOURCE PLANNING PROCESS AND THE PLANNING TECHNIQUES THAT YOU USE?

A. At APS, the resource planning process consists of both a technical analysis stage and a management decision stage. The former involves several discrete analyses that are then integrated into a specific recommendation or series of recommendations to upper management at APS. These technical analyses include: (1) project-specific economics; (2) Western markets regional resource planning studies; (3) wholesale market price forecast studies; (4) busbar cost determinations; and (5) long-range fuel and purchased power cost forecasts. These allow APS to determine how a prospective generating project fits into the Company's existing resource package, what are its opportunities to sell power off-system to reduce busbar costs to APS consumers, what are APS' opportunities to buy power (both short and long-term) rather than construct new generation, and what is the price and supply risk for both the proposed generating project and its alternatives. A more detailed description of these five separate but interrelated analyses is set forth below.

- *Project-specific economics.* We analyze the value of any new project – whether to "buy or build" – based on discounted cash flows under a variety of assumptions. This analysis allows us to determine a project's expected internal rate of return ("IRR") and its incremental contribution to earnings (in the case of an unregulated project) or its incremental value in reducing revenue requirements (in the case of a regulated project). Please note that these are complimentary concepts. The same project that would maximize profits for a merchant generator (because its costs are that much less than the expected value of its output) will minimize revenue requirements in a regulated cost-of-service environment, again because its costs are below the costs of alternatives. It is generally the case that any project that has an IRR greater than the cost of equity will produce savings to consumers under cost-of-service regulation. The analysis necessarily takes into account revenues and margins from both the retail and wholesale markets. Indeed, the ability of a project to effectively compete in the wholesale market during those periods of the day or year when it is not being used to serve retail load has progressively taken on more importance with the development of a more competitive wholesale market in the late 1990s.

- *Regional Resource Planning Studies.* In a competitive wholesale generation market, regional studies assume a critical role for the regulated utility as well as an unregulated generation company. In the wholesale market, power costs are largely determined by the regional supply-demand generation balance and the region's transmission adequacy. Traditionally, utility resource planning focused primarily on the individual utility by simulating a single electrical system such as that of APS. Beginning in the mid-1990s, APS began to put more emphasis on regional simulations, which analyze the interaction of large-scale interconnected systems like the WECC. This kind of analysis allowed us to determine the power supply and demand situation for the entire region, and to evaluate projected regional demand in the context of regional transmission and generation resources.

- *Wholesale Market Price Forecast Studies.* Although related to the Regional Resource Planning Study, the former is intended to look at the supply and demand dynamics of the regional wholesale market. In contrast, the purpose of wholesale market studies is to produce a market price forecast. With the passage of the 1992 National Energy Policy Act, utilities began to anticipate and prepare for greater reliance on the wholesale power market. Also anticipating this change in the industry, we improved our ability to forecast forward prices throughout the region with more sophisticated modeling tools. With this kind of market price analysis, we can derive forecasts of the availability and cost of wholesale market supplies throughout the West. This analytical tool improved the accuracy of our discounted cash flow studies used for our "buy vs. build" scenarios, both project-specific and generic.

- *Busbar Cost Determinations.* For every significant potential long-term purchase or new generation construction project, we analyzed the potential incremental and total effect on APS customer prices by preparing a comprehensive revenue requirement or busbar cost analysis. In doing so, we looked at the cost of power from the new project and integrated that with the existing generation portfolio to determine the new average price for the entire new generation portfolio. A busbar cost analysis determines the cost of power at the generation bus, including capital costs. A traditional busbar cost analysis forms the basis for determining the revenue required to pay for the capital and operating costs of utility assets at an assumed rate of return on equity and capital structure. We performed the test to ensure APS generation was competitively positioned and the impact on APS customer prices was quantified.

- *Long-range fuel and purchased power cost forecasts.* These studies form the basis for a number of corporate operational and financial planning decisions. We typically incorporate forecasts by outside groups as to fuel prices, power plant capacity factors, or financial information and adapt their data to our specific situation. We may also reformat that data so that it can be used in the existing APS corporate software models. In addition to providing quantitative input for these models, we can use the forecasts in sensitivity analyses to determine price and supply risk profiles for different resource alternatives. Fuel and purchased power forecasts also form a baseline from which "buy vs. build" and other resource planning analyses emerge.

Q. WHAT DID YOU DO WITH ALL THESE STUDIES?

A. The results from these various technical analyses were then integrated, summarized, and presented to top APS management for review. These presentations offered actionable alternatives for decision-making by APS officers or Board members, or both. As I will demonstrate in the balance of my testimony, we not only planned these units to meet APS customer growth, but these assets were also found to be of significant long-term economic value to our customers. Our resource planning decisions were based on a thorough understanding of the Western markets, an essential ingredient for planning of new generation assets in a more competitive market environment. Every step of the way from the inception of the project to a next decision point and/or change in the critical assumptions used to arrive at the previous decision, we re-evaluated the economic viability in support of continuation of the project(s). When continued economic support for the projects was not justified, further commitments were stopped or altered.

Q. DO SOME OR ALL OF THESE RESOURCE PLANNING ANALYSES REQUIRE WHOLESALE MARKET DATA TO BE GATHERED OR ESTIMATED?

A. Yes. Not only must we look at what is available or likely to be available in the market, we have to incorporate estimates of unit operating characteristics, fuel prices and availability, and wholesale power prices, among other factors. Under traditional regulation, much of this data was filed with various regulatory agencies and generally available. With the advent of wholesale competition on a wide scale, the cost data underpinning the market has become much less transparent.

Q. CAN YOU DESCRIBE THE VARIOUS METHODS OF GATHERING MARKET INTELLIGENCE AND PRICE DISCOVERY USED IN THE ABSENCE OF A TRANSPARENT WHOLESALE POWER MARKET?

A. Yes. We tested the wholesale market in a variety of ways. In addition to issuing a formal request for proposal ("RFP") in 1995, which will be discussed later in my testimony, we used four additional methods. First, valuable market data was obtained through the conduct of the Company's day-to-day business, which obviously includes sales and purchases from the wholesale electric market. Second, APS (and later PWEC) explored and discussed partnering with other market participants such as Reliant, U.S. Generating and Calpine, which allowed us insights into their view of the then current and future wholesale market. Third, APS simulated through computer modeling the WECC regional and sub-regional (Arizona/New Mexico) energy and capacity markets. Finally, APS performed internal financial and economic evaluations of both available generation technologies and known purchased power options in the West.

Q. WOULD YOU EXPLAIN EACH OF THESE FOUR METHODS OF ASSESSING THE WHOLESALE MARKET?

A. By conducting business daily in the wholesale market, we contacted suppliers routinely to determine whether they had power available and the price they were asking. As electricity markets moved toward restructuring and wholesale trading activity increased, electricity products were standardized for electronic commodity trading. At least at first, price information became more readily available. This was a very valuable source of information, especially from the late 1990s through 2001. However, since the California market failure, trading at various market hubs has become very "thin," especially for more than a year or two out, and some markets have either collapsed altogether (California Power Exchange) or stopped trading electricity until very recently (New York Mercantile Exchange). Thus, today's published market data is suspect at times and should be extrapolated with regard to larger volumes and more remote delivery dates only with extreme caution.

By forming partnerships or co-tenancies with other companies, historically APS has sought to improve its overall generation system efficiency and simultaneously reduce the risk exposure of APS customers. Examples include the joint ownership of the Palo Verde, Four Corners, Navajo and Cholla power plants. In recent years, we have had numerous discussions with utilities and merchant generators in an effort to find the best combination of generation assets for our customers and to spread the risk of large power station projects. These discussions helped us to periodically "take the pulse" of the market.

On a regular basis, we simulated the regional and sub-regional energy and capacity markets for the WECC using regional software planning tools such as the General Electric Multi-Area Production Simulation Program ("MAPS"). This program, which we have modified considerably to model our specific situation here in the Southwest, allows us to simulate a "dispatch" of the entire WECC generation and transmission system. In this manner, APS could test various expansions or contractions of resource scenarios for their impact on marginal generation costs, which in turn set market prices. With this sophisticated simulation, we identified various regional and sub-regional generation capacity deficits or surpluses, pinpointed the existence and impact of load pockets in transmission-constrained areas, identified other areas where additional capacity will be needed to serve customers and specified cost-effective locations for building new generation capacity. As I explain later in my testimony, finding a potentially cost-effective location, which must consider both the busbar cost of the generator and its access to off-system markets, reduces customer costs.

Finally, and perhaps most importantly, the information gathered from the above regional market studies allowed us to perform our own economic and financial evaluations of the available alternatives for meeting customer demand. Our evaluations enabled us to choose the best option (best, that is, from the combined point of view of cost, reliability, and risk) from the available alternatives—either buying or build alternatives—that result in the most customer-beneficial projects. The Company relies on a variety of methods in preparing the energy and peak demand forecasts. These methods include end use analysis, econometric model development, expert opinion, customer contact, and trend analysis related to retail and native load wholesale customer demand in the Company's service territory. The methods used to produce the load forecast are consistent with methods that are used across the industry and are similar to the methods that were documented in each of the Company's past Integrated Resource Planning ("IRP") practices and filings (in 1992 and 1995) to this Commission.

Q. DOES THE RESOURCE PLANNING PROCESS DEPEND UPON LONG-TERM FORECASTS OF APS LOAD REQUIREMENTS?

A. Yes.

Q. PLEASE DISCUSS THE APS LOAD FORECASTING PROCESS.

A. The load forecast prepared at APS for its Arizona customers includes total APS service territory expected retail load plus demand from cost-of-service based wholesale contracts. The full requirement wholesale contracts in the past had amounted to over 300 MW of load. Today they contribute only about 7-8 MW of coincident peak demand in the forecast.

About 90% of APS energy sales are made to "mass market" residential and small to medium business customers, with the remaining 10% to large business customers. This latter group has discrete load requirements and growth trends, and thus, forecasts of energy sales to these customers are made with specific input from them on their expected operating plans. The residential energy forecast is derived from both econometric and end-use studies. The small to medium commercial sales forecast is derived from an econometric model using independent factors such as job growth, office and retail floor space additions, the price of electricity and weather effects.

The peak demand forecast is then determined by applying class-specific load factors to the projected customer class sales forecasts and adding line losses. Historical information on class load factors results from a reconciliation of each year's system peak with the results from a randomly drawn statistical sample of retail customers. Changes in the seasonality of the retail sales forecast are controlled by calculating the historical load factors with summer period sales only, and extrapolating the trend in the load factors through the forecast horizon.

Both energy and peak load forecasts of APS service territory include transmission and distribution system losses. System loss rates coincident with the system peak are based on historical observation on the EHV system and engineering estimates of distribution level losses. These system loss rates are also trended into the future to develop the forecast.

Historically, APS has reviewed its customer load forecasting data and associated assumptions twice a year. A short-term (normally up to 5 years) customer peak and energy forecast is carefully reviewed in the fall upon good knowledge of the most recent system summer conditions. The longer-term (up to 20 years) load forecast is established in the spring and also becomes a basis for generation planning, fuel forecasting and financial forecasting.

APS' current forecast expects energy sales to grow at an average annual rate of 4.3%, with higher growth rates occurring in the near term as the economy and associated electricity demand recovers from the downturn in economic activity. This compares with the most recent 5-year average growth rate from 1997 to 2002, on a weather-normalized basis, of 3.4% and the corresponding 10-year average growth rate of 3.4%. Demand growth is estimated at 4.2% per year, which is actually slightly less than our actual experience over the 10-year period.

Q. WERE THE APS LOAD FORECASTING PROCESS AND RESULTS ACHIEVED FROM THE PROCESS YOU HAVE DESCRIBED ABOVE CONSISTENT WITH INDUSTRY PRACTICES?

A. Yes. Although the APS load forecasting process has continuously been improving, it has always used state-of-the-art industry standard software, computer tools and practices. Historically at APS, the load-forecasting group was comprised of a management team from many disciplines within the Company. It also coordinated its efforts with the industry (WECC) and neighboring systems, although this is increasingly difficult in today's competitive business environment.

Q. HOW WERE THESE RESULTS INCORPORATED IN YOUR RESOURCE PLANNING?

A. These results, along with APS' customer electricity use patterns and customer peak load and energy demand forecast, allowed us to prepare APS system specific resource planning studies. We periodically reviewed APS' customer supply and demand balance and identified capacity and energy shortfalls. We prepared annual and sometimes more frequent L & R plans for APS load balance. Many of these plans have been previously provided to the Commission or its Staff. The L & R studies are the basis for APS daily system operation, construction budgets, fuel planning, and the Company's overall financial forecast.

B. Planning History- Past and Recent Impacts

Q. HAS APS EXPERIENCED GENERATION PLANNING CYCLES OVER THE YEARS?

A. During the last thirty years with APS, I have seen several cycles of generation construction programs. Each was necessarily built upon existing resources while incorporating the Company's views concerning future events. Going back to the early 1950s, APS served its customers' needs primarily with oil and gas-fired plants. Our customer load was relatively flat and did not exhibit the high summer peak demand we have since experienced. By the 1960s and early 70s, the strong growth within our service area coupled with technological advances and better economic conditions allowed more customers to afford refrigerated air-conditioning and pools. APS' customer demand grew at an annual rate of over 7%. To complement our historic base of gas and oil-fired generation, we built or acquired ownership interests in large coal plants such as Four Corners, Cholla and Navajo. They diversified the Company's fuel mix and served our growing service area efficiently with low-cost base-load capacity.

In the 1970s, APS continued to grow rapidly. The Company found itself in need of peaking capacity, and APS added quick-start gas turbine units at our existing plant sites in Tempe, Phoenix and Yuma. Population growth in the Valley and in Arizona during the 1970s and 1980s continued to increase customer demand, which was now growing at the staggering average rate of 8.5% per year in our service territory. By 1978, natural gas could not legally be burned as a boiler fuel for electricity production from new units, and additional coal was a difficult resource option due to increasing environmental constraints. APS' increased customer needs were met with nuclear energy by constructing a jointly-owned large power project at Palo Verde. And of course, as our customer demand called for additional generation supplies, at the beginning of this century we built generation at Redhawk, West Phoenix and Saguaro to assure the future reliability of APS service.

Q. WHAT HAVE WE LEARNED FROM THESE PAST GENERATION CONSTRUCTION CYCLES?

A. When APS moved from a utility dependent almost entirely on small oil and gas generating units to adding the large coal units at Cholla, Four Corners, and Navajo during the 1960s and 1970s, it created upward pressure on prices in the near term. But coal protected our customers from the full effects of the oil and gas price shocks and shortages of the time. Similarly, the construction of Palo Verde in the 1980s severely stressed the Company's financial condition and led to several rate increases. And yet, it was the efficiency of these units that allowed for the more than decade-long rate stability and even rate decreases that have marked the Company's experience in the 1990s and into this century.

Q. WHAT DOES THE SUPPLY-DEMAND BALANCE IN THE LATE 1980S AND EARLY 1990S ILLUSTRATE ABOUT THE CONCEPT OF "LUMPINESS" IN GENERATION AND TRANSMISSION CAPACITY?

A. As we emerged from the 1980s and into the early 1990s, the entire WECC and our sub-region had more than enough generating capacity. APS itself had sufficient capacity, primarily because of the addition of the nuclear units at Palo Verde. The cost efficiencies of nuclear power required APS to add large increments of this new capacity, and thus it was anticipated that APS would have more than adequate capacity for at least several years.

This process of adding large amounts of capacity with the completion of a new project – common in the planning process for both generation and transmission assets – is often referred to as "lumpiness." The capacity added is necessarily larger than the immediate need, but the lumpiness gets "smoothed out" and the cost efficiencies begin to appear as load grows and the resource becomes progressively more fully and more frequently utilized. In fact, it is almost impossible to gain the long-term cost efficiencies of large facilities without experiencing some initial "lumpiness."

Q. IS "LUMPINESS" ONLY ASSOCIATED WITH THE PHYSICAL ATTRIBUTES OF NEW GENERATION SUCH AS NET CAPACITY OR CAPACITY FACTOR?

A. No. The capital costs of new generation are also proportionately greater than that of older, more-depreciated generation. That is the primary reason why the inclusion of the PWEC generation in the Company's rate base causes an increase in overall revenue requirements. This is not at all unusual, as can be seen by my earlier discussion of the impact of adding coal and nuclear generation during past generation construction cycles.

Q. HOW DID THE MORE RECENT RESOURCE PLANNING HISTORY AT APS AND PWEC LEAD TO THE EVENTUAL DECISION TO CONSTRUCT NEW GENERATION?

A. A year-by-year review of our APS resource planning activities demonstrates the extraordinary volatility of the last eight years and our flexibility and agility in responding to unprecedented changes in regulation and the marketplace. This review also illustrates that we were carefully monitoring the APS capacity deficit in the context of a then capacity surplus in the WECC as a whole. In this regard, 1995 was the appropriate place to start because all the relevant planning studies for our decision to construct the PWEC assets began with the 1995 Integrated

Resource Plan ("IRP") filing. This IRP was filed with the Commission under the provisions of the Commission's IRP regulations. Equally important was the 1995 RFP to which I have previously referred in my testimony. At that time, we were making and planned to continue to make relatively modest purchases in the competitive wholesale market in addition to our long-term contracts. There did not appear to be a significant reliability need for several years.

Q. PLEASE DISCUSS THE 1995 RFP AND ITS SIGNIFICANCE IN SUBSEQUENT RESOURCE PLANNING DECISIONS.

A. In conjunction with the 1995 IRP, which was filed in late December of that year with the Commission, the Company issued an RFP. APS then had the option to convert its existing purchases from Pacificorp (obtained in the early 1990s as part of the Cholla Unit 4 sale, which, along with the Pacificorp contract itself, was approved by the Commission) to a full seasonal exchange beginning in 1996. To test the economics of that option, APS issued an RFP to some 34 entities having some presence, either current or announced, in the WECC. From that RFP, we received seven responses.

None of the proposals could match the economics of the Pacificorp seasonal exchange, and thus APS elected that option. However, the responses were nonetheless very informative. Virtually no responding party wished to enter into the 10-20 year agreement APS was soliciting, and those that did would do so only by constructing a new plant in the Southwest with the APS contract supporting its construction. This indicated to APS that the regional surplus of capacity was not likely to extend significantly longer than would the Company's own period of having sufficient capacity. Moreover, APS should not expect to obtain long-term purchased power agreements at costs less than the cost of constructing its own new plants and quite likely higher.

Another interesting fact, the significance of which can best be appreciated in hindsight, was that the two highest-rated entities responding to our RFP from the standpoint of creditworthiness and financial stability were Enron and U.S. Generating, both of which are now bankrupt less than eight years later. If we had signed a 10-20 year agreement with either or these entities on favorable terms, it is likely we would be in the same position as Connecticut Power & Light, which is facing termination of its favorable agreement with NRG by a Bankruptcy Court.

Q. WHAT TOOK PLACE IN THE YEARS IMMEDIATELY FOLLOWING 1995?

A. In 1996 and 1997, we continued to refine our models and review our resource needs as we monitored the development of competition in California as well as Arizona. In 1996, MAPS became a major tool for our planning analyses, significantly advancing our ability to model regional supply and demand and to forecast locational prices. MAPS also accounted for and anticipated transmission congestion issues.

Also in 1996, California passed its restructuring legislation, AB 1890. AB 1890 froze customer rates after a 10-percent reduction, implemented retail competition immediately and established a California Independent System Operator ("CAISO") to operate the transmission system. AB 1890 also set up a California Power Exchange ("CPX") to operate a short-term wholesale power market based on a pooling of resources (i.e., all generation is sold into a single "pool" from which load serving entities also purchase their needs, usually through day-ahead transactions). APS simulated the operation of the California "Poolco" market, attempting to determine its effect on wholesale prices in the WECC and any unintended consequences for APS wholesale and retail prices. These analyses demonstrated the risk to APS and its customers from divestiture and became the basis of the Company's position on that issue.

In 1997, APS also began to see signs that customer demand in the Valley and Arizona as a whole was growing faster than had been previously forecast. The load forecast for 2003 grew from 4413 MW (in the 1995 IRP) to 4774 MW in the 1996 long-range forecast. It then increased to 4980 MW in the 1997 forecast. This represented a nearly 13% increase in just two years.

Also in 1997, APS carried out the kinds of generation planning activities described earlier – evaluating generation needs, providing fuel and purchased power budgets and forecasts, and carrying out regional simulations including the effects of California restructuring. APS made a technology assessment to determine the most economical generation technology for APS load. Anticipating the potential coming of restructuring in Arizona, APS developed a discounted cash flow financial model to calculate IRR as a supplement to the traditional revenue requirement and busbar cost analyses. The most immediate issue that these new planning tools had to address was the potential for acquiring additional shares of plants APS was already operating or at least had an existing ownership interest.

At this time, the California utilities were planning to sell most of their generation assets. As joint owner of some generating units with Southern California Edison Company ("SCE"), we examined the economic feasibility of acquiring SCE's share of Palo Verde and Four Corners. Because El Paso Electric Company ("El Paso") also had often expressed an interest in selling its share of Palo Verde, we evaluated the value of that share of these projects as well. These units were well placed both to serve APS customers and to access regional markets for off-system sales margins. They also had proven track records of performance and would not need new siting authority or land acquisition.

Q. WHAT HAPPENED NEXT?

A. Toward the end of 1997, APS had conducted a number of market assessments that were incorporated in our long-range forecast in early 1998. The purpose of these market assessments were to determine whether APS customers could expect any reduction in costs if the Company purchased large amounts of power from the competitive market instead of acquiring or building additional generation.

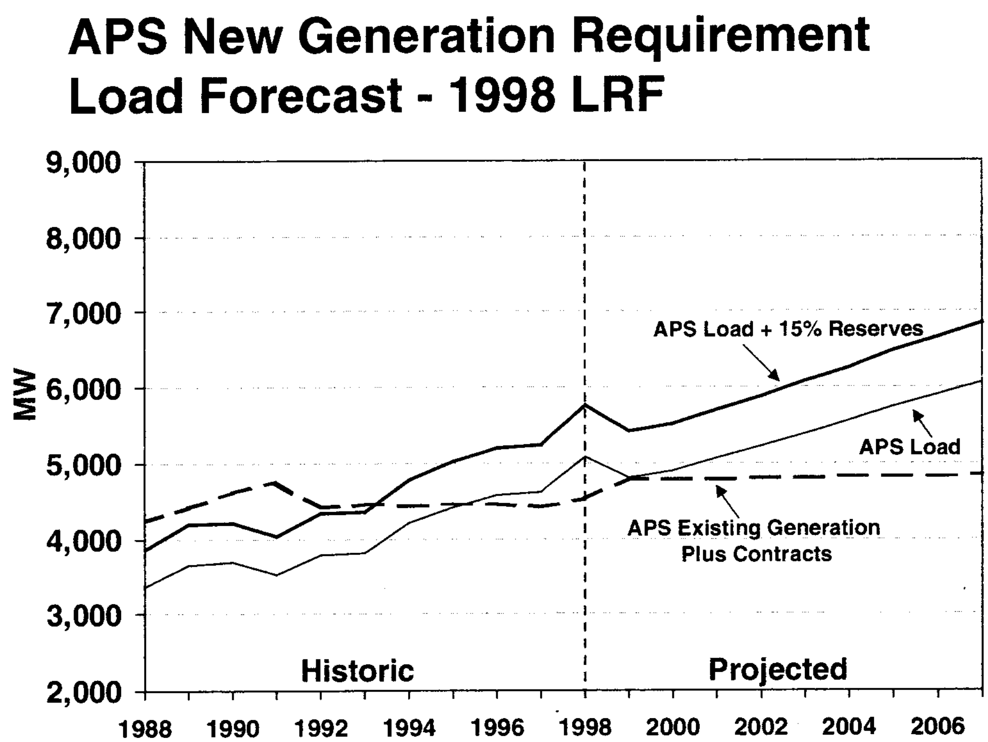
In this analysis, the Company assumed a fully functional and effective CPX and CAISO. Another conservative assumption was made in the study to avoid later allegations that the analysis might be biased in favor of constructing new generation. Specifically, it was assumed that APS' construction cost for new gas-fired projects would be 10 to 20% higher than the cost to merchant generators. This was largely due to the belief that a merchant generation project would be generally project-financed, thus allowing higher leverage, and we also speculated that the merchant generators might initially accept a lower initial return on equity in an attempt to achieve or increase their market share.

Using these cost assumptions, we compared two basic scenarios – one in which we began a construction program in 2001 to met APS' customer needs and a second in which we relied on the wholesale market. Note that APS had already decided that any new capacity would have to begin somewhat earlier than before in view of the higher customer growth. The results of this analysis slightly favored relying on the competitive market over new construction. However, our analyses (which I will return to later) always supported buying additional shares of our existing jointly owned generating assets, such as Palo Verde, Four Corners or Navajo. As a result of this study, and for planning purposes, APS increased its anticipated reliance on the competitive market to as much as 1000 MW through 2004. APS continued to believe that no major new construction was required until 2004.

This relative calm was to end quickly. The summer of 1998 saw a soaring actual peak demand, which exceeded 5000 MW for the first time. This 1998 peak was in excess of the 1997 forecast for 2003, and thus represented an increase in load growth of some five years in a little over one year. SRP was experiencing similar unanticipated load growth, and Nevada also was growing rapidly. Percentage-wise, California was growing at a slower pace, but with its incredible size compared with other western states, it was gobbling up capacity at an alarming rate. APS needed to revise its plan from the 1995-1997 period in light of this new data.

Planning activities once again thoroughly reviewed the Western generation markets and continued with the assessment of the potential for purchasing jointly owned existing units that we operated. We also analyzed the potential of various new generation sites around the WECC through our regional planning model and determined that Arizona was not as attractive a market to merchant generators as California and Nevada. By October of 1998, APS had reviewed the regional situation – both neighboring utilities and the WECC as a whole – and concluded that the Southwest was becoming unacceptably short of capacity and dependent on imports. Both of these latter findings were very significant to the "buy vs. build" decision rapidly being forced upon the Company. If this shortfall continued, and if Arizona had to compete with California for new generation, APS and its customers would be exposed to very significant and, in our judgment, unacceptable risks of higher purchased power costs. System reliability was also in danger of being compromised, especially considering that no economic analysis performed by APS showed that the most profitable location for a merchant plant would be within metro-Phoenix. Figure 4 illustrates the increasing gap between APS-owned generation and APS load that we saw developing in future years by mid-1998.

FIGURE 4



At this point, we began studies to identify a new generation site or sites capable of accommodating 1500 to 2000 megawatts. The official recognition in an APS planning document of what was the project called "Hedgehog" (later renamed as Redhawk) appeared as part of our Generation Growth Plan in January 1999.

Q. WHAT DID YOUR 1999 LONG-RANGE FORECAST INDICATE ABOUT APS GENERATION NEEDS AT THE TIME THE DECISION WAS MADE TO BUILD THE PWEC UNITS?

A. At the time when the current version of the Electric Competition Rules was being considered by the Commission in 1999, the generation deficit at APS was growing to an alarming level and was projected to approach nearly 2200 MW by 2007. Our projections also showed other utilities in the Desert Southwest were becoming increasingly short of generation capacity and no, or very little, apparent merchant activity in the region. And our analyses of the western generation and transmission system were increasingly revealing overloads of the transmission grids and significant generation import issues within major load centers like Phoenix.

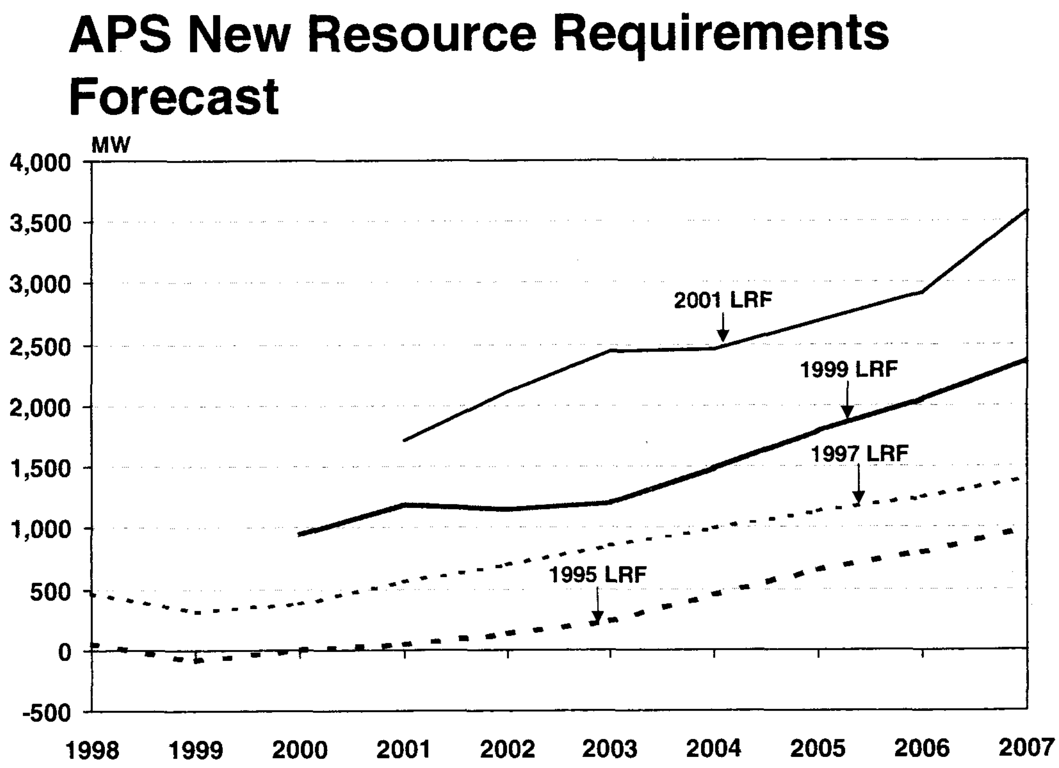
But while increasing demand was the dominant factor affecting our planning decisions, it was by no means the only influence. The effect of restructuring the electric industry in California and other nearby states as well as Arizona had to be factored into our decisions. In Arizona, specifically, we had to consider the possible effect of divesting our generation assets to one or more companies. APS maintained forcefully before this Commission that it, or at least an affiliate, needed to retain control of our existing and any future generation assets to avoid exposure to the risks of a totally fragmented, potentially dysfunctional and, if not unregulated, certainly under-regulated, wholesale market.

Q. COULD YOU SPECIFICALLY ADDRESS THE ESCALATING LOAD GROWTH SITUATION FACED BY APS?

A. APS experienced a strong acceleration of load growth within its control area that had a dramatic impact on projections of the Company's future resource needs. A pictorial representation of APS' changing annual load forecast (including 15%

reserves) between 1995 and 2001 and corresponding additional new generation requirement for the projected year 2003 is shown below in Figure 5.

FIGURE 5



Q. WHAT PLANNING STUDIES WERE PERFORMED BY APS IN 1998-99 TO ASSURE THAT THERE WOULD BE AN ADEQUATE GENERATION SUPPLY FOR THE EXPECTED HIGH LOAD GROWTH IN THE COMPANY'S SERVICE TERRITORY?

A. In anticipation of high load growth within the APS service territory, a series of regional generation planning studies, beginning both prior to and extending after the summer of 1998, became part of the strategic planning for the new reliability generation construction program at APS. The economics of building new generation in Arizona vs. elsewhere in the WECC, the depressed electric wholesale market prices and the increasingly negative regional supply situation, both of neighboring utilities and the WECC as a whole, were all analyzed. We concluded that along with Arizona, the Southwest was also becoming unacceptably short of generating capacity and increasingly dependent on imports beyond the transmission system's capabilities. Our market intelligence research group found that all the independent power producers' known generation activities were elsewhere in the United States and especially in California. There was no or very little activity in Arizona. APS system reliability became our paramount concern. Thus, our new generation program was initiated in late 1998.

Q. WERE OTHER NON-BUILD OPTIONS CONSIDERED TO ENSURE ADEQUATE GENERATION SUPPLY FOR APS INCREASED GROWTH?

A. Yes. We undertook a comprehensive review of market alternatives, including all existing and jointly-owned assets potentially available for sale in the Southwest and potential new generation construction sites in Arizona and elsewhere in the WECC. Among all the jointly-owned assets options identified, SCE's share of Palo Verde and Four Corners, TEP's share of Navajo and Four Corners, and El Paso's share of Four Corners and Palo Verde were seriously considered. In Attachment AB-4, I show an example of our economic historical analyses of the busbar cost of these possible acquisitions. It is compared both with the assets PWEC expected to receive from APS and the planned Redhawk and West Phoenix projects. The subsequent acquisition of these interests in the existing Palo Verde, Four Corners and Navajo plants was negotiated with varying degrees of initial success. However, for various reasons, all of these efforts eventually failed.

Q. WHAT DID YOUR LONG-RANGE FORECAST INDICATE ABOUT THE RESOURCES NEEDED FOR ARIZONA AND THE DESERT SOUTHWEST?

A. Our long-range forecasts showed that Arizona and the Southwest needed to import capacity during the peak summer months. For Arizona as a whole, our 1998 forecast predicted statewide total demand in 2003 of 12,897 MW and resources of 11,633 MW, a deficit of 3199 MW even with a moderate 15% reserve margin. In the Desert Southwest, we forecasted in year 2003 total demand of 20,701 MW and resources of 17,848 MW, a deficit of 5958 MW.

For these and other reasons, we became concerned about APS system reliability. There was considerable doubt as to whether the transmission system would be able to import enough capacity into the Southwest and Arizona at times of peak demand, even if capacity were available at a reasonable cost from other states or regions. After all, the load elsewhere in Arizona and also in Southern Nevada was growing at least as fast as APS load. In addition to these concerns, we were unsure about the effect the new California market structure would have on the Western wholesale market. Because California is such a huge market in comparison with Arizona and the rest of the western states, even on a cumulative basis, we knew the impact of that California market on the Southwest would be both significant and difficult to predict.

Q. AT THE TIME YOU DECIDED TO BUILD THE WEST PHOENIX AND REDHAWK UNITS, WAS MERCHANT CAPACITY AVAILABLE IN ARIZONA TO MEET THE NEEDS OF APS CUSTOMERS?

A. No. At the time we made the corporate commitment in late 1998 to build the West Phoenix and Redhawk units, the rapid increase in potential Arizona merchant plant activity was still in the future. By the spring of 1999, when West Phoenix was officially announced, there were still only three merchant plants announced or under construction in Arizona. These were the South Point, Griffith, and Desert Basin facilities. All three of these plants were announced in late 1998. The locations of South Point and Griffith in the far northwest corner of Arizona, outside our service area and transmission system, indicated that those plants were targeting California and Nevada markets. Desert Basin was eventually to be committed to SRP. Moreover, none of these plants would be of any use in serving load within the constrained metro-Phoenix area during peak, which was becoming an increasing reliability concern to APS in the late 1990s.

Even by the time the formal public announcement was made concerning Redhawk in September 1999, only two additional new plants had been announced. And those announcements had been made only a mere couple of weeks earlier. These new plants were SRP's 225 MW Kyrene facility and Sempra's 1000 MW Mesquite plant.

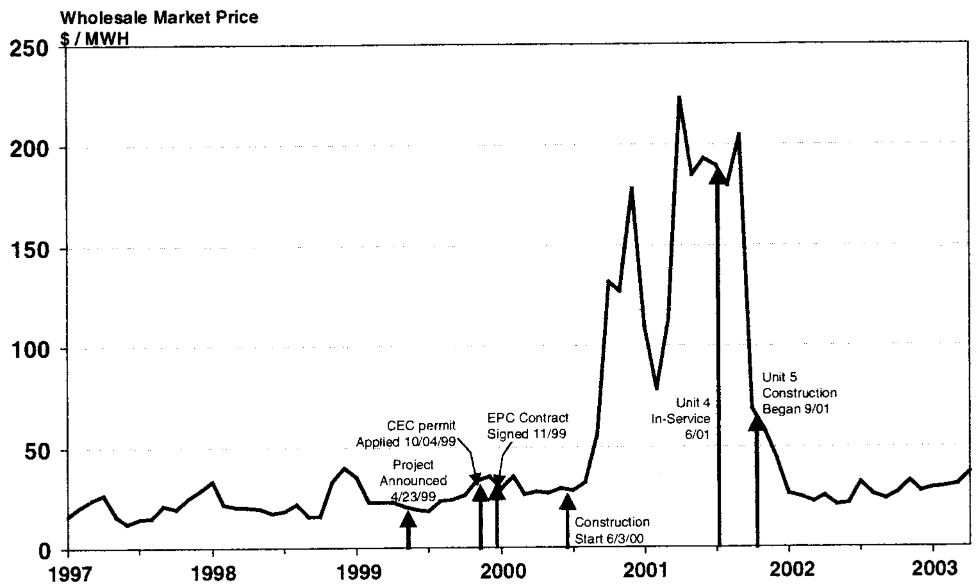
Kyrene was neither a merchant plant nor one likely to solve the Company's long-term resource needs. SRP was constructing this relatively small plant to serve its own retail load and showed no interest in either partnering on the project or having APS acquire any of Kyrene's output. Moreover, SRP did not bid either of its new generating facilities (Kyrene and Santan) in the recent APS Track B solicitation. Sempra contracted the Mesquite plant to California, as expected, and also did not participate in the recent APS Track B solicitation process.

Q. DID PWEC BUILD ITS ARIZONA POWER PLANTS IN HOPES OF EXPLOITING THE CALIFORNIA MARKET PROBLEMS?

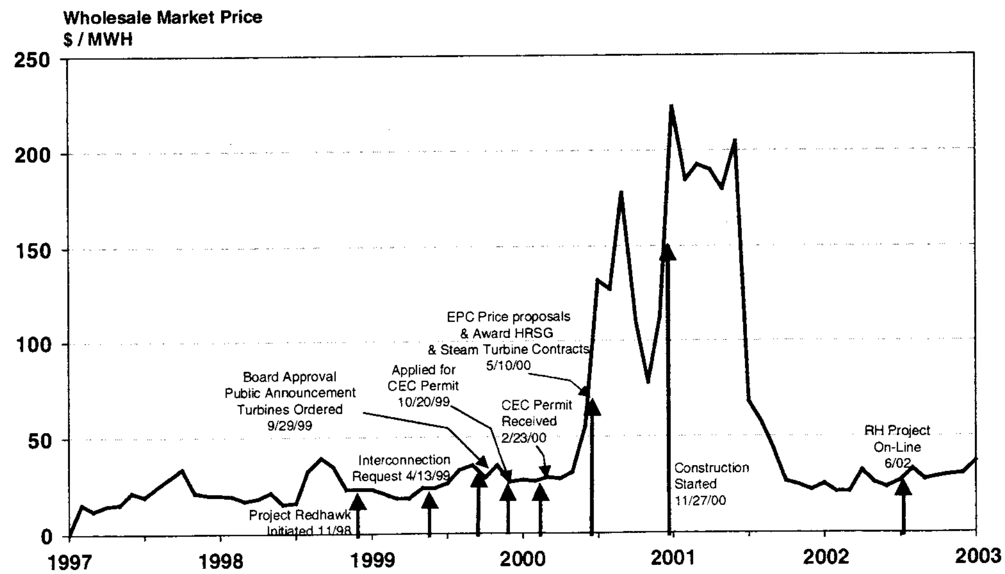
A. The goal was serving APS, not California. Although off-system sales are an important part of all power plant economics, PWEC announced and began implementation of its plans for the West Phoenix and Redhawk power plants before the rapid increase in Western power prices. This timing is shown graphically for both West Phoenix and Redhawk in Figures 6 and 7, below.

FIGURES 6 AND 7

West Phoenix Project Major Events



Redhawk Project Major Events



But during the California-induced power crisis of 2000-01, a number of new merchant plants were begun in Arizona. Those plants clearly were intended to capitalize on the run-up in prices, and this intention has been confirmed by the subsequent cancellation of some of these plants as power prices fell.

This contrast in timing is no coincidence. PWEC's construction plans were driven by the need to supply APS customers with reliable power. And the timing was none too soon for APS. By the time construction of West Phoenix and Redhawk began in June and November 2000, respectively, the Western power crisis had begun and keeping the lights on in Arizona without bankrupting the Company or the state was clearly going to be a challenge.

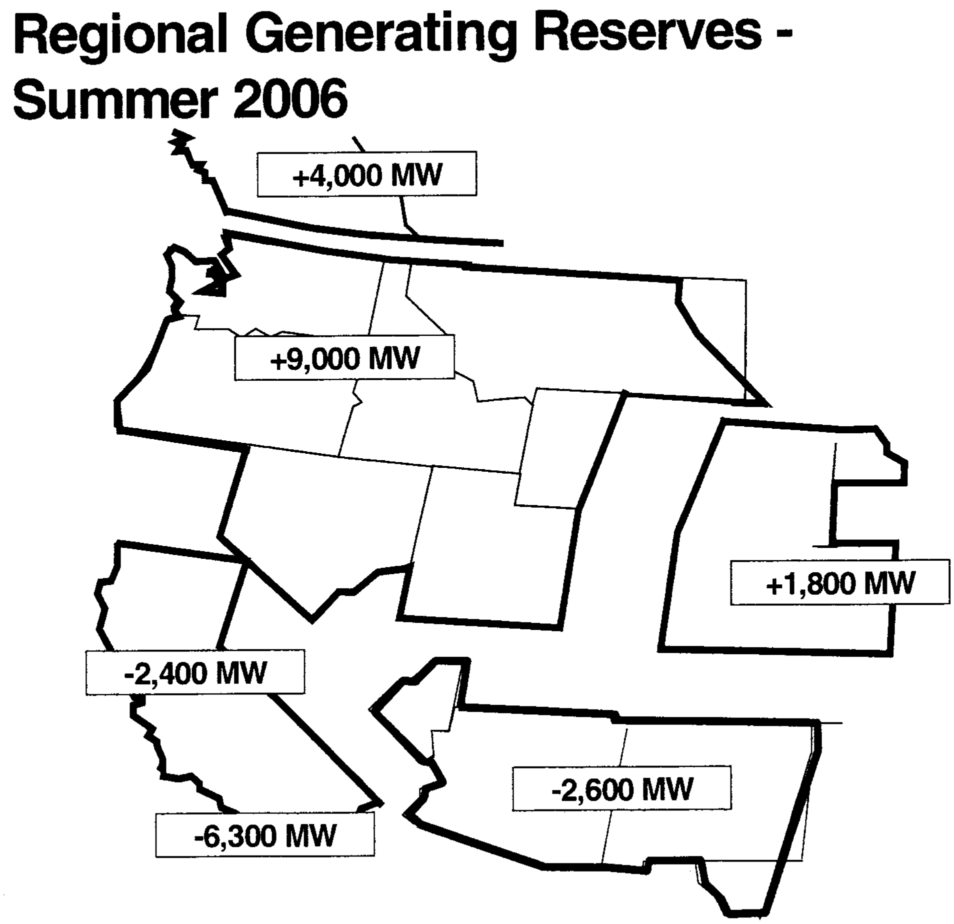
Q. HOW DID THE REGIONAL AND WESTERN TRANSMISSION SITUATION AFFECT YOUR EVALUATION OF APS RESOURCE NEEDS?

A. While our earlier 1995-97 planning studies showed that the WECC had an excess of capacity, we also recognized that the Western transmission system did not allow interstate power transfers in sufficient amounts to accommodate increasing demand growth in Arizona and the Southwest. There are constraints within the WECC system outside APS' control that prevent the power from flowing into our area, and within the APS system there are additional constraints, some of which I have already discussed and others that exist due to the geography of our service area.

Further, we knew that increasing amounts of wholesale power exchange under various competitive scenarios could put additional strain on the Western transmission system, possibly in unpredictable ways. As noted by numerous studies and articles on competition, the transmission networks in the U.S. were built primarily by local utilities to provide power from remote utility-owned generation to their service areas. They were not designed or constructed to serve as common carriers for massive interstate exchanges of power between systems and regions in furtherance of a national competitive wholesale market scheme.

In the West, the transmission transfer capabilities were likewise inadequate to allow us to substantially increase our purchases from remote locations. As shown in Figure 8, which came from a management presentation in 1999, the largest available reserves were located in the Pacific Northwest, but the major transmission links to and from that region go primarily to Northern California, not to the Southwest.

FIGURE 8

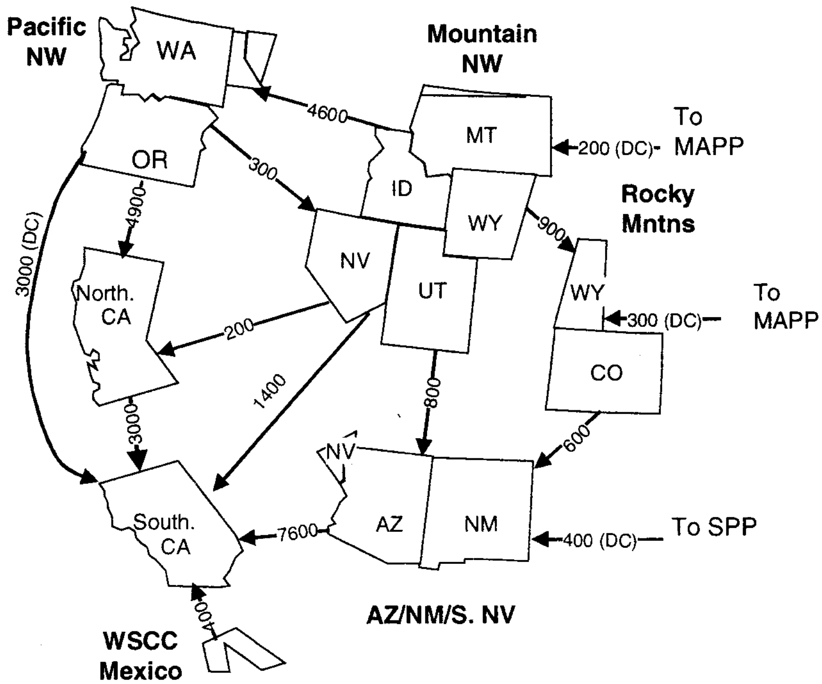


This condition was unlikely to change because at the time, California also had a significant capacity deficit. This would have encouraged an even stronger transmission link with the Northwest, but made it even less probable that power would flow from the Northwest through California to Arizona. There were and are substantial transmission links between Southern California and Arizona, but Southern California's capacity deficit (6300 MW) was well over twice that of the entire Desert Southwest (2600 MW). Given the relative economic advantage of transmitting power to California as compared to Arizona, it was doubtful that significant Northwest power not already under contract to APS (such as the Pacificorp agreement) could be bid away by APS or any other Southwest utility.

The transmission pathway from Utah into Arizona allows for the transfer of up to 800 MW from the Northwest into Arizona, but this pathway also encounters a constraint at the Four Corners substation, which limits the incremental import potential to approximately 200 MW. In part, this is because the APS diversity exchange of 480 MW with Pacificorp uses the same transmission path to bring power to our customers during the summer months. It is also because Four Corners, and its related substation and transmission system, is owned by utilities in Arizona, New Mexico, Texas and California. As I discussed earlier, the transmission system in that area was primarily designed and sized to transfer power from Four Corners to the Southwest and Southern California service territories of the owner entities and not to wheel power from Utah through New Mexico into Arizona. Figure 9, which was also originally prepared in 1999, shows the regional transmission transfer limitations facing the Southwest in general and APS in particular.

FIGURE 9

Western Power Markets Transfer Capability (MW)



Q. WHAT EFFECT DID THE CALIFORNIA DEBACLE HAVE ON RESOURCE PLANNING DURING THE YEAR 2000?

A. The year 2000 saw momentous events in the Western power markets—unprecedented high power prices and shortages, high natural gas prices and the complete failure of the wholesale market structure. These events had three primary effects on APS resource planning: elimination of the SCE purchase option due to legislation barring further divestiture of generation in California, acceleration of the reliability projects at West Phoenix, and a re-evaluation of projected WECC market prices and supply-demand balance.

In early 2000, PWEC received Certificates of Environmental Compatibility for our West Phoenix and Redhawk facilities, respectively. Although we had considered partnership arrangements for both of these projects – Calpine with West Phoenix and Reliant with Redhawk, these plans had assumed that at least some of the acquisition scenarios would pan out and did not fully consider the tremendous explosion in customer demand we saw in 1999.

In 1999 and 2000, APS continued to experience customer growth at three times the national average, as the expansion phase of the business cycle reached unprecedented levels not seen in previous economic cycles post-World War II. APS was forced to continuously revise its load forecasts upward to account for this new phenomenon. Nor could this explosion in growth be viewed simply in isolation, considering the supply problems and extreme price volatility being experienced in California and other Western states. Thus, APS became increasingly concerned about its ever-growing capacity deficit. We knew that an unusually hot summer could put extreme pressure on reliability in the absence of the new PWEC units. Moreover, APS' financial situation could become strained if the Company were forced to buy power on the open market at exorbitant prices, thus threatening the rate reductions under the 1999 Settlement.

APS was able to maintain Valley reliability in the summer of 2000 with the re-commissioning of its old West Phoenix 4 and 6 units, but it was clear that more dramatic measures would be needed for 2001 and beyond. Although by this time, several other merchant generators had announced plans to build near Palo Verde, their units would not be on line in time to meet our needs. Nor did we have any assurance that these units would even be interested in Arizona given the lucrative market in California. Therefore, and as a result of a study made in August of 2000, PWEC advanced the planned in-service dates for the first two Redhawk units from 2003/2004 to 2002 and the last unit (Unit 4) from 2009 to 2005.

The acceleration of the construction schedule for Redhawk (so as to have the capacity available for APS customers by 2002) carried with it some unintended consequences. The energy from the plant would likely be more than could be used solely to serve APS native load for at least the first couple of years. Thus, we developed a plan to provide some capacity and energy to the wholesale market during off-peak periods. This resulted in some opportunity costs to PWEC because this off-system capacity and energy would be more valuable if construction could have been delayed until the market shortage in the West was even more acute and prices higher. But our study continued to show that a combined portfolio of existing APS generation and new PWEC gas-fired plants produced lower costs than relying exclusively on the wholesale market, whose structural flaws had become glaringly obvious.

Q. WHAT EFFECT DID THE AFTERMATH OF THE CALIFORNIA DEBACLE HAVE ON YOUR PLANNING DURING 2001-2002?

A. The California debacle and Western power crisis provided a direct – but not always clear and certainly not preordained – path to this proceeding and our request to put the PWEC Arizona assets into the APS rate base. The year 2001 began with continuing high prices and California power emergencies, even during the winter months when prices were expected to moderate. By early in the year, the California utilities were nearly bankrupt, and the state, through the California Department of Water Resources, took over the purchase of power for utility customers.

To assure reliable service during the summer of 2001, PWEC completed construction of WP-4, while APS maintained the West Phoenix Steam Units 4 and

6, which had been re-commissioned the prior year, for another summer. PWEC also brought in temporary, trailer-mounted generation at both West Phoenix and Saguaro. We spent an estimated $120 million to protect APS customers during this extremely uncertain and volatile time in the power and natural gas markets. This foresight paid off when on July 2, 2001, peak demand reached 5687 MW. We were able to meet that demand, but even with WP-4 and PWEC's trailer-mounted generation, APS was down to 36 MW of reserves in the Valley.

By operating existing units at the highest level and adding new capacity, some of it on an emergency basis, we assured reliable service to customers and protected them from skyrocketing market prices. These same high market prices bankrupted one of the nation's largest utilities, put severe strains on many others, and led to hefty rate increases for the customers of many Western utilities. In my opinion, our response demonstrates the Company's commitment to its customers. These actions also demonstrate our ability to remain agile enough to make short-term adjustments within the context of a longer-term asset-based resource plan.

As we prepared to move the APS generation to PWEC, we knew that APS would be required to buy all of its power on the wholesale market, with 50% through an undefined auction or bidding process. Facing this prospect, given the dysfunctional nature of the California and Western power markets, was daunting and extremely risky for APS customers. As a result, we developed and filed with the Commission in the fall of 2001 a plan to preserve an orderly progression toward competition and for PWEC to guarantee APS customers a reliable supply of affordable power. APS believed that the proposed long-term cost-based purchased power agreement with PWEC, combined with mandatory open market purchases based on fixed formula, would allow divestiture to proceed and for the wholesale market in Arizona to develop over time, while still protecting APS customers.

During the latter half of 2001 the Western power markets collapsed. By the fall of 2001, the Enron scandal further eroded confidence in power markets and trading activity. And by the beginning of 2002, the merchant power industry was already beginning to falter. Although these events temporarily removed the threat of skyrocketing power prices, they introduced the new issues of counter-party credit risk, thinning markets, and the parade of project cancellations that will eventually lead once again to capacity shortages later this decade. All of this reinforced the Company's belief that having the existing APS assets as well as the new PWEC assets available for APS customers in a single integrated package at reasonable cost-of-service prices would be a better option. Under the terms of the Electric Competition Rules and the 1999 Settlement, such unification of assets could only take place within PWEC.

Although recognizing the same problems as APS, the Commission decided to change course altogether and stopped the divestiture of APS generation in Decision No. 65154 (September 10, 2002). This provided APS customers with a partial market hedge similar to that envisioned by APS, but also resulted in the PWEC gas-fired assets being stranded at PWEC.

Q. COULD YOU SUMMARIZE THE REASONS WHY APS DECIDED TO PURSUE AN ASSET-BACKED CONSTRUCTION PROGRAM TO SATISFY ITS FUTURE NEEEDS RATHER THAN RELYING EXCLUSIVELY ON THE WHOLESALE MARKET OR BUYING EXISTING CAPACITY?

A. As I have previously discussed, APS looked at each of these options, both individually and in combination, from 1995 through 2001. For construction scenarios, all technologies' (gas / coal / nuclear) economics were evaluated on a relative basis and sited at a generic location with varying unit sizes and configuration. The risk of building gas-fired generation directly controlled by APS or an affiliate of APS proved to be lower for both our customers and for APS than the risk of not building and thus allowing APS customers to be exposed to an unpredictable, uncontrollable, and unreliable wholesale market. This was because the construction of modern gas-fired generation does not involve the sort of construction-related risks one faced in the past when building coal or nuclear generation. And with this gas-fired generation likely to be the market-setting marginal resource, it was extremely unlikely that the wholesale market would produce a lower long-run price than the cost of building one's own generation.

C. Regulatory Background to APS Planning Decisions

Q. HOW DID REGULATORY ISSUES INFLUENCE THE PLANNING PROCESS OVER THE LAST DECADE?

A. This period was a time of considerable change and uncertainty in the economic and regulatory arenas. Beginning in 1994 with the issuance of the California "Blue Book"—essentially a manifesto for retail competition—it was evident that our huge neighboring state, as well as the Federal Energy Regulatory Commission ("FERC") would look for ways to promote competitive elements in the electric utility industry.

Q. WHAT WERE THE MAJOR REGULATORY ISSUES IN ARIZONA AT THIS TIME?

A. There was a widespread belief that competition and deregulation were inevitable and that other states needed to get on the bandwagon or they would be left behind by California and the handful of jurisdictions that were seriously looking at this issue. Arizona was not immune to this growing enthusiasm for restructuring and deregulation, and the Commission opened a docket investigating electric industry restructuring in 1994, although there was little activity in that docket until 1996, when the Commission enacted the first version of the Electric Competition Rules.

Q. DID THESE RULES ATTEMPT TO CHANGE THE VERTICALLY INTEGRATED STRUCTURE OF APS OR REQUIRE DIVESTITURE OF THE COMPANY'S GENERATION?

A. No. In fact, the Commission rejected mandatory divestiture, although its generic "stranded cost" order in 1997 did allow it as an optional means of valuing an electric utility's "stranded costs." That position appeared to suddenly change in 1998, and by August of that year, mandatory divestiture was added to the Electric Competition Rules as an "emergency" measure. APS was successful, however, in persuading the Commission to allow divestiture to take place to an affiliate of APS rather than to one of the then-emerging merchant generators. This switch in regulatory policy from vertical integration to mandatory divestiture of generation was further reflected in the 1998 three-way settlement among APS, TEP and Commission Staff, as well as the finalization of the "emergency" Electric Competition Rules in December of 1998.

Q. DIDN'T THE COMMISSION REVISIT THE ELECTRIC COMPETITION RULES IN 1999?

A. Yes. The "permanent" 1998 Electric Competition Rules lasted less than a month before a new Commission set them aside. But although several aspects of the Rules were subsequently changed, the Commission held steadfastly by the concept of mandatory divestiture in the set of Electric Competition Rules that were approved early in the fall of 1999.

Q. HOW DID THE 1999 APS SETTLEMENT AGREEMENT FIT INTO ALL THIS?

A. Just as had the failed 1998 three-way settlement, the 1999 Settlement called for divestiture of generation to an affiliate of APS. This was changed slightly by the Commission to be a direct subsidiary of Pinnacle West rather than a subsidiary of APS, as had been envisioned by the actual settlement itself. APS also was permitted an additional two years to accomplish divestiture as compared to the requirements of the Electric Competition Rules.

The 1999 Settlement also called for a Code of Conduct, as did the 1999 version of the Electric Competition Rules. This Code of Conduct was approved by the Commission in early 2000 and, I was told at the time, effectively prohibited APS from constructing new generation even during the "window" prior to divestiture, which now extended through 2002. APS agreed to this restriction because, given the Commission's clear preference for divesting generation, it would have been imprudent, even unimaginable, for APS to construct generation that it then would have to divest before such generation was, for the most part, completed and placed into service.

Q. WAS ARIZONA ALONE IN REQUIRING DIVESTITURE OF GENERATION?

A. No. In the West, California, Nevada and Montana all required divestiture but did not have the foresight to allow for that divestiture to be to an affiliate of the incumbent vertically integrated utility. Divestiture also was required or encouraged elsewhere in the country.

Q. DID THE REQUIREMENT TO DIVEST APS GENERATION AND TO NOT CONSTRUCT NEW GENERATION AT APS AFFECT THE COMPANY'S OBLIGATION TO RELIABLY SERVE AS PROVIDER OF LAST RESORT WITHIN ITS SERVICE AREA OR TO PLAN FOR ITS FUTURE NEEDS IN THAT REGARD?

A. No, but it did complicate that effort. Owning generation gives a utility the ultimate physical hedge against market risk and provides operational and financial flexibility not easily obtainable through mere contracts for power. Divestiture also meant that APS' superior capital raising ability could not be used to finance any needed new resources. Building such new resources at PWEC was clearly a "second best" option compared with continued integration of APS, but it was just as clearly the best option then available to discharge the Company's public service obligation.

Q. HOW DID ALL THESE REGULATORY EVENTS INFLUENCE YOUR RESOURCE PLANNING PROCESS?

A. With the Commission's Electric Competition Rules finally approved and the 1999 APS Settlement in effect, generation planning shifted emphasis from the regulated to the competitive arena. APS agreed to shift its generation to a competitive generation affiliate, PWEC, which was created in September 1999. However, we continued to view the primary mission of that generation affiliate as the provision of reliable and economical power to APS customers, albeit at market determined rates under FERC jurisdiction rather than traditional Commission-regulated cost-of-service prices. The resource planning process at APS and subsequently at PWEC continued to explore various generation alternatives and market and regulatory scenarios to quantify inherent risk associated with all of these events. For example, we reviewed the possible implications of the generation transfer for APS. In June 1999, we conducted an analysis entitled "1999 Planning Scenarios Risk Assessment." The analysis concluded that blending existing APS generation with the new construction being planned would result in lower costs to APS customers than would open market purchases. This confirmed to APS the wisdom of maintaining this blend of generation in an affiliate where it could still be dedicated to serving APS.

Q. DID EVENTS GO AS HAD BEEN ANTICIPATED, EITHER IN ARIZONA OR IN THESE OTHER STATES TO WHICH YOU REFERRED?

A. Yes and no. During 1998 and most of 1999 wholesale power prices were, as expected, very low. Then in 2000, the situation changed dramatically. Power prices began to soar in the California market. Brownouts and blackouts occurred in California and spread to other parts of the West. Although APS had anticipated that electric markets, like all commodity markets, would be volatile and had determined even during the "soft" power price period of 1998-1999 to protect its customers from that volatility and to ensure reliability here in the Valley, I cannot claim that we predicted the full scope of the ensuing disaster. Thus, it was decided in 2001 that a study should be done to analyze the impact on APS and APS customers of various possible regulatory reactions to the California situation.

Q. WHAT WERE THE SCOPE AND RESULTS OF THIS 2001 MARKET STRUCTURE STUDY?

A. In early 2001, at the height of the California crisis, APS Resource Planning undertook an analysis of the impact differing market structures would have on APS customers. We identified four potential alternatives for analysis:

- Current Path (Divestiture and Deregulation)
- Current Path (Bilateral Agreement with PWEC for full-requirements)
- Partial Regulation
- Return to Vertical Integration

Under the Current Path-Divestiture and Deregulation scenario, APS would transfer its generation assets to PWEC and acquire all of its needs from the competitive market as required by the Competition Rules and the 1999 Settlement Agreement. The PWEC generation assets (including the transferred APS assets) could still serve APS, but at market-determined prices, and would compete for sales in the general wholesale market, where its diverse and low-cost portfolio would provide significant competitive advantages.

Under the Current Path-Bilateral Contract scenario, APS would also continue with the planned transfer of its generation assets to PWEC, as required by the Arizona Competition Rules and the 1999 Settlement. PWEC and Pinnacle West would then seek Commission permission to provide a "full requirements" service to APS reflecting the cost of the combined (at PWEC) portfolio of APS and PWEC generation as well as the cost of supplemental power purchased from the competitive market. This scenario formed the basis of our proposal in the fall of 2001 for a purchased power agreement between PWEC and APS and a corresponding request for a partial variance to the Electric Competition Rules.

Under the Partial Regulation scenario, APS would retain its existing generation assets under cost-based regulation and obtain all of its unmet needs from the wholesale market. PWEC's new generation assets would compete for sales in the wholesale market. This scenario was inconsistent with either the competitive model required under the Electric Competition Rules or the traditional regulatory scheme in effect for many decades prior to the Electric Competition Rules. It also was not practical in any event, because WP-4 and WP-5 were necessary for reliable service to APS customers in the Valley. Thus, we did not fully complete this particular analysis.

Under the Return to Full Regulation scenario, APS would continue to own generation assets – both its own existing assets and the assets being constructed by its affiliate PWEC. These assets would be included in the Company's rate base under cost-of-service ratemaking, including recovery of cost of capital. The wholesale market would still fill a vital role of providing "economy energy" sales and purchases as well as capacity to cover any deficit during periods of high demand. It would also provide an alternative for future load growth, but APS could continue to have the option of building new utility-owned generation assets as needed to meet future customer demands.

Q. WHAT WERE THE RESULTS OF THIS ANALYSIS?

A. Because Option 4 (Return to Vertical Integration) did not materially differ from Option 2, I have focused my analysis here on Option 4. Our analysis showed significant volatility inherent in the deregulation scenarios. The Return to Vertical Integration scenario was found to be the most beneficial and financially attractive scenario for APS customers. I have calculated the savings anticipated for APS customers from Option 4 as compared to Option 1. This scenario provided average savings in the range of $250 million for our customers just in 2005 alone. The savings for other years were comparable. And although a large amount of these savings come from the continued cost-of-service regulation of the existing APS generation, the analysis also showed anticipated 2005 customer savings in the range of $22-74 million from the new PWEC generation.

Q. HAVE YOU PREPARED A TIMELINE THAT PUTS ALL OF THESE REGULATORY, MARKET AND APS PLANNING AND CONSTRUCTION EVENTS INTO CONTEXT?

A. It would be impossible to do that on a single chart or graph. There were just too many events that led to the current situation, as I have described in my testimony.

However, as noted in my Summary, I have prepared a simplified timeline as Attachment AB-1 that depicts at least the major events in Arizona, the region and nation, and for APS/PWEC planning and construction of the PWEC assets. This timeline will allow the reader to get a better feeling as to how all of these various pieces fit together.

V. ECONOMIC ANALYSES OF THE PWEC ASSETS

Q. YOU HAVE TESTIFIED THAT YOU CONDUCTED ECONOMIC ANALYSES IN ADDITION TO THAT DISCUSSED IN CONJUNCTION WITH THE POSSIBLE REGULATORY REACTIONS TO THE CALIFORNIA ENERGY CRISIS THAT SUPPORTED THESE CONCERNS ABOUT RELIANCE ON THE WHOLESALE MARKET. WOULD YOU DISCUSS THEM IN MORE DETAIL?

A. Yes. As I have stated previously in my testimony, economic assessments of the economic viability of constructing these units were made repeatedly. Project IRR was estimated based on our forecast of the wholesale market revenues and project costs. We also continued with conventional revenue requirement measurements through analyses of busbar costs. In fact, we computed each project's revenue requirements / busbar cost at every major milestone during the planning and initial construction phases. We compared the relative competitiveness of these new units, both combined with the existing APS generation that was to be divested to PWEC and separately, with other merchant generators in the vicinity or to spot wholesale market prices. These results supported our conclusion that we were prudently planning and constructing these units for APS customers.

Q. WILL YOU DESCRIBE THE RESULTS OF YOUR IRR STUDIES FOR THE PWEC ASSETS UNDER CONSIDERATION IN THIS PROCEEDING?

A. Yes. During the course of the 36-month period of that encompassed the planning and initial construction phases of the PWEC assets, we prepared numerous IRR analyses on the Redhawk units, WP-4, WP-5 and Saguaro CT-3. Attachment AB-5 summarizes IRR results for the each of the PWEC assets. Each and every study represented this Attachment showed life-cycle IRR for Redhawk of 12% or better using then-anticipated market prices. Similar studies for WP-4 and WP-5 were also performed and the results of these studies are also provided on Attachment AB-5. Since Saguaro CT-3 was completed with an accelerated schedule, two study results are provided for this project in Attachment AB-5.

Q. PLEASE DISCUSS YOUR REVENUE REQUIREMENT / BUSBAR COST STUDIES.

A. We prepared busbar cost studies for the PWEC generation using the same set of operating and fuel cost assumptions used for our IRR analyses. Both the IRR and busbar analyses indicated that the PWEC generation assets were prudent economic resource additions for the Company and its customers if they could be constructed at reasonable cost. However, because the assets were needed also for reliability, it was equally important for them to be timely completed from the viewpoint of APS system requirements.

Q. HOW DID THESE IRR MODEL RESULTS SHOW ANTICIPATED BENEFITS TO APS CUSTOMERS?

A. As I explained earlier in my testimony, the higher a project's IRR, the lower the cost the project will be for customers under a regulated costs-of-service regulatory regime. I have reviewed the previously developed IRR results provided in Attachment AB-5 referenced above and compared them with the potential project revenue requirements under cost-of-service regulation. I have used cost-of-capital assumptions of the time, which were somewhat higher than what APS is requesting in this case. This tends to overstate the cost-of-service revenue requirement as compared to today. Operating and market price assumptions were also based on the same data as the original IRR and busbar cost analyses.

My analysis shows that rate-basing the PWEC reliability assets could have been anticipated to yield a benefit ranging from approximately $496 million to $615 million in net present value over the life of the projects. The discount rates used in my analysis are between 8.25% and 7.1%, after tax, the former of which was consistent with the average cost-of-capital also used in the original IRR and busbar analyses, while the latter reflects the after-tax cost-of-capital requested in this proceeding. Once again these results and conclusions are drawn from studies conducted while these assets were being planned and justified to management and thus are the studies that directly relate to the prudence of constructing the PWEC assets to serve APS.

VI. <u>THE PWEC GENERATION ASSETS WERE PRUDENTLY AND TIMELY CONSTRUCTED, AND THEIR AS-BUILT COST WAS REASONABLE</u>

Q. WOULD YOU PLEASE DISCUSS THE TIME DURATION BETWEEN PLANNING, CONSTRUCTION AND IN-SERVICE OF YOUR RELIABILITY UNITS?

A. The assets constructed by PWEC were state-of-the-art combined cycle and combustion turbine units. Unlike previously constructed long lead-time (10-20 years) nuclear and coal units, the reliability assets took less than three years to complete. The Redhawk project was announced in late September 1999, received its CEC permit on February 23, 2000, finalized its engineering, procurement and construction ("EPC") contract on September 2000, began its construction on late November 2000, and was brought on-line in summer of 2002. This was all in accordance with the accelerated schedule established for Redhawk's completion in the third quarter of 2000.

WP-4 and WP-5 were announced to the public in late April 1999 and received their CEC permit on February 17, 2000. The WP-4 EPC contract was awarded in November 1999. Construction began the following June and was completed before the Summer of 2001. WP- 5's EPC contract was signed in May 2001, construction began September 2001, and the projected in-service date for this unit is July 2003.

The Saguaro CT-3 project was awarded an EPC contract in August 2001. Construction began October of 2001, and commercial operation was achieved before the summer of 2002. Because of its size, Saguaro CT-3 did not require a CEC.

In each of these instances, the PWEC units were constructed in time to address the Company's reliability needs. And in no instance was there a significant overrun in the construction schedule anticipated when construction actually began.

Q. HOW WERE THE CONSTRUCTION COST ESTIMATES DEVELOPED FOR THE RELIABILITY ASSETS?

A. The construction cost estimates for the Redhawk and West Phoenix units can be characterized into four phases: (1) the planning phase; (2) the development phase; (3) the phase just before construction commencement; and (4) the construction phase. I might also add that there were also unique events specific to each project. For example, the construction and timing of WP-4 were accelerated by turbine availability from a previously suspended project. Both WP-5 and Redhawk were at one time considered as jointly-owned projects, and Saguaro CT-3 was built, in part, in lieu of continued use of temporary generation.

Q. PLEASE EXPLAIN FURTHER HOW YOU ARRIVED AT THE CONSTRUCTION COST ESTIMATES FOR EACH OF THESE PHASES IN GENERAL?

A. The construction cost estimate for most of our reliability generation during the planning phase followed the normal standards of generation planning process at APS. The generic technology-specific construction cost data was provided by our

Engineering Department. This allowed us to compare a project's relative economics to another.

In the development phase, site-specific construction cost estimates were prepared based on certain contacts with major equipment suppliers and the EPC contractor. This phase did not consider more detailed cost estimates associated with the project transmission, water and specific equipment design, Such site-specific and transmission-related studies are performed in tandem later in the project.

In the case of the PWEC assets, the major equipment suppliers, project design work, and engineering services were obtained through competitive RFPs to minimize cost. Then, the project construction cost estimates were refined further through the competitive procurement process itself. These estimates were finally supplemented with other ancillary project equipment costs. Taken together, these steps provided the best estimate available prior to the construction phase itself.

The construction cost estimates and/or commitments (also know as budgets) were monitored regularly from this time forward. Contractual, environmental or regulatory requirements were the most common reasons for further modifications of project cost from the previous phase. These direct project costs along with interest accumulated during construction ("IDC") became the final project construction costs.

Q. HOW DID WP-4'S "AS-BUILT" COSTS COMPARE TO THE PLANNING ESTIMATED AMOUNT PRIOR TO CONSTRUCTION COMPLETION?

A. During the planning phase of the project, the construction cost data was estimated based on our engineering judgments and input from the EPC contractor. In June 2000, and prior to construction, the cost estimate of WP-4 was set at $75 million, not including IDC and any necessary spare parts inventory. WP-4's final cost was $78 million, including spare parts and allowing for an incentive payment to the EPC contractor for its timely construction of this much-needed facility.

Q. WHAT CONSTRUCTION COST DATA FOR WP-5 UNIT DO YOU HAVE?

A. During the initial planning stages (November 1999) for its two-on-one combined cycle configuration, WP-5's preliminary construction cost data was estimated to be $251 million, which was only an engineering estimate made without any input from the EPC contractor and did not include additional environmental or transmission-related equipment. That estimate was revised upward by $30 million taking into consideration input from the EPC contractor, major equipment contractors. The present as-built estimate for WP-5 is $292 million, including spare parts and transmission improvements. I do not consider this figure to be significantly higher than the final pre-construction estimate.

Q. DO YOU HAVE A SIMILAR ANALYSIS OF THE TWO REDHAWK UNITS?

A. Yes. The Redhawk units were initially (September 1999) planned as four 500 MW units using Westinghouse turbines and were estimated to cost roughly $1 billion in total based on the preliminary engineering estimate. The failed partnership with Reliant did allow APS to substitute GE turbines, which facilitated an in-service date coincident with APS needs, albeit at a somewhat higher cost. Redhawk project cost estimates were also revised to include additional transmission line costs and spare parts. Thus, in July 2001, the new project cost for the four units was estimated to be $1.13 billion based on the actual contracts awarded for the project. The as-built cost of Redhawk 1 and 2 was $572 million, only slightly more on a per unit basis than the final estimate. PWEC wrote off Unit 3 and 4 costs of approximately $50 million, and these costs are not a part of this rate proceeding.

Q. PLEASE CONTINUE BY DISCUSSING SAGUARO CT-3?

A. The schedule for the Saguaro simple cycle project was for it to be in service to meet APS 2002 peak load at a cost estimated at $40 million. Actual as-built cost was a little below that estimate, or $37 million. This unit took the place of the temporary rental turbines used in 2001, which I have previously discussed.

Q. HOW DOES THE COST OF THE PWEC UNITS COMPARE WITH THE COST OF SIMILAR UNITS BUILT AT THE SAME TIME IN ARIZONA?

A. Because the main cost components (gas turbines, steam turbine and steam generating equipment) are common to any combined cycle installation, there is little room for significant cost variations from one installation to another. However, based on public data released by other builders on their projected costs for like installations, the PWEC unit costs are comparable to and would appear to be competitive with similar units of the same vintage. In fact, these assets were roughly 5% less per installed kW ($570/kW versus $596/kW) than the average of other similarly-vintaged plants in Arizona. Of course, as I noted earlier, the actual book value of the PWEC assets asked for inclusion in the Company's rate base is somewhat less due to the depreciation and deferred taxes from their in-service date through their estimated date of acquisition by APS.

Q. HOW DID YOU KEEP THE COST OF THE PWEC UNITS WITHIN A REASONABLE RANGE?

A. In addition to using competitive RFPs where appropriate, PWEC used a series of incentives for the contractors to meet or beat scheduled dates and entered in other contracting partnerships to keep both the cost targets and service date schedules within a reasonable range. These strategic alliances, along with having PWEC staff on site during the construction phase, allowed these projects to be completed at a reasonable cost.

Q. WERE CONSTRUCTION COSTS FOR THE REDHAWK AND WEST PHOENIX PROJECTS REVIEWED BY AN INDEPENDENT CONSULTANT?

A. Yes. In 2000/2001, PWEC retained Stone and Webster, an engineering and energy consulting firm, to review Redhawk-1 and Redhawk-2 and also WP-4. (At this time, WP-5's major contracts were being negotiated and were not available to S&W for their review. However, they were not materially different than those for Redhawk.) In their written report, Stone and Webster reviewed: 1) plant design and major equipment; 2) the EPC contracts; 3) combustion turbine supply and installation; 4) the heat recovery steam generator acquisition; 5) the steam turbine acquisition; 6) the brine concentrator acquisition; 7) all transmission agreements; 8) equipment performance and availability; 9) natural gas availability; 10) proposed implementation schedule; 11) estimated capital costs; 12) projected O&M; 13) permitting requirements and permitting status; and 14) environmental assessment of the facility. Stone and Webster concluded that both Redhawk and West Phoenix were being constructed in full conformance with accepted industry practices and anticipated project costs were reasonable.

VII. <u>CONCLUSION</u>

Q. WOULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS?

A. First of all, the PWEC assets were built to serve APS customer load and have done so. Their unique location near the load center makes them, both in terms of reliability and economics, superior generating assets to other alternatives considered at the time. This did not happen by chance, but was instead the result of a prudent and comprehensive resource planning process. Secondly, the results of the recent Track B power supply solicitation conducted by APS clearly confirm what our resources studies have repeatedly shown. The PWEC assets are necessary to reliably serve APS customers both in the short and long-term. Third, the PWEC assets provide significant operating benefits to the Company and its customers by providing needed voltage support and the flexibility to economically displace less efficient generation. Finally, these assets will be acquired by APS and included in the rate base at their 2004 depreciated cost. This provides significant long-term economic savings to APS customers.

Q. DOES THAT CONCLUDE YOUR WRITTEN DIRECT TESTIMONY?

A. Yes.

APPENDIX A

STATEMENT OF WITNESS QUALIFICATIONS

Ajit P. Bhatti is Vice President of Resource Planning for Arizona Public Service Company. Mr. Bhatti was elected to this position in December 2002 and is responsible for developing generation plans and evaluating strategic initiatives for APS. He is a veteran of the electric utility industry with over thirty (30) years of experience in Western generation and transmission system modeling and planning.

Mr. Bhatti joined the Company in 1973 and has held management positions at varying capacities since June 1986. In 1990, he was named Manager of the Resource Planning Department and in 1998 Mr. Bhatti was named Director of the same. In that position, he was responsible for identifying electric generation deficits of the APS system and providing long-range planning of the generation resources. In 2000, Mr. Bhatti was elected to Vice President of Generation Planning for Pinnacle West Energy Corporation (the then newly-formed subsidiary of Pinnacle West Capital Corporation) and was responsible for providing long-range planning for the enterprise' generation resources.

Mr. Bhatti maintains extensive knowledge in the Western generation and transmission systems and power markets. During his career, he has developed computer models to simulate local and regional electric systems. He has extensive expertise in utility integrated resource planning, generation modeling, generation technology economic analysis and system planning. He was extensively involved in originating the Company's generation strategies with Pacificorp that resulted in substantial benefits for APS' customers.

Mr. Bhatti has led regional planning task forces and authored reports related to regional transmission plans in the Southwest. He has previously testified before the Arizona Corporation Commission related to the Company's IRP filings. He has also provided testimony in proceedings before the Interstate Commerce Commission (now the Surface Transportation Board of the United States Department of Transportation). Those proceedings were initiated by the Company in 1994 against the Santa Fe Railway (now the Burlington Northern Santa Fe Railway) to investigate the reasonableness of rail rates charged by the rail carrier for transport of coal from mines in New Mexico to the Company's power plant in Arizona. Mr. Bhatti's testimony addressed the modeling of the electric system to demonstrate the impact that tariffs charged by the railroad had upon the dispatching of APS electric generating assets.

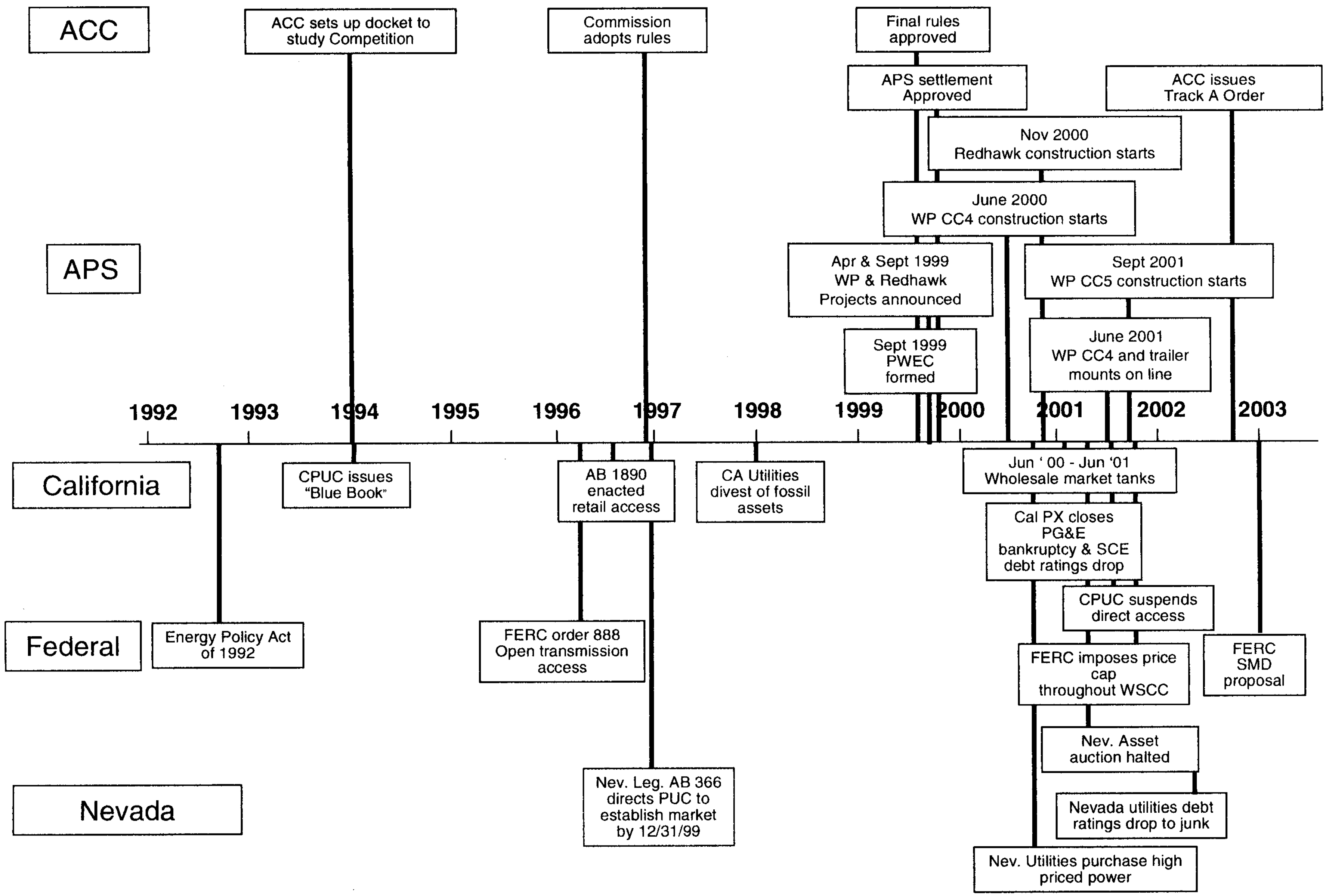
Mr. Bhatti has made presentations to rating agencies, financial analysts and to industry forums. He is routinely called on by the Company's Board of Directors to provide insights on the Western electric markets and the Company's generation plans.

Mr. Bhatti holds Bachelor and Masters Degrees in Electrical Engineering from New Mexico State University. He has been a registered professional engineer specializing in electricity in the State of Arizona since February 1977.

Attachments

Attachment AB-1

Time Lines Related to Restructuring Electric Industry

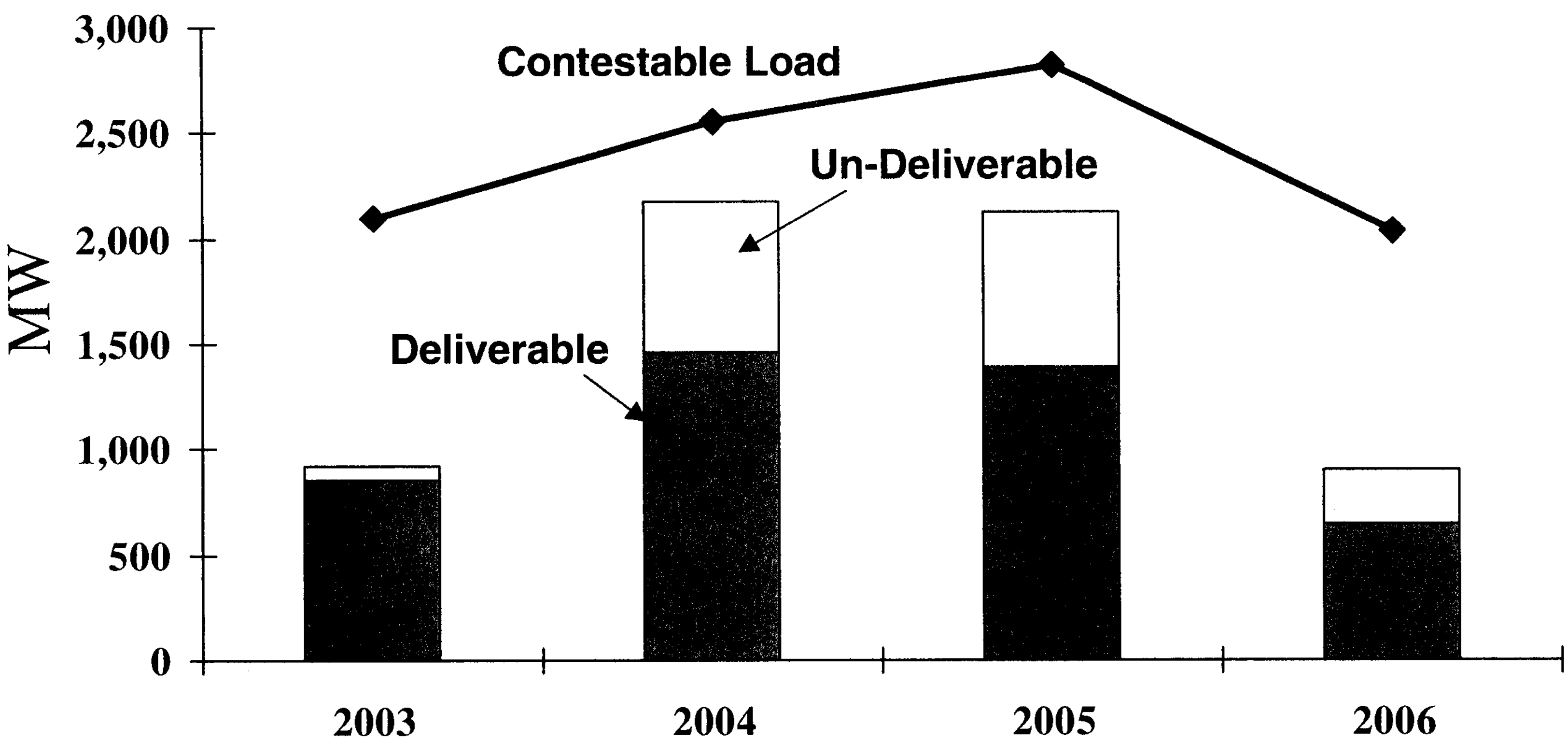


Attachment AB-2

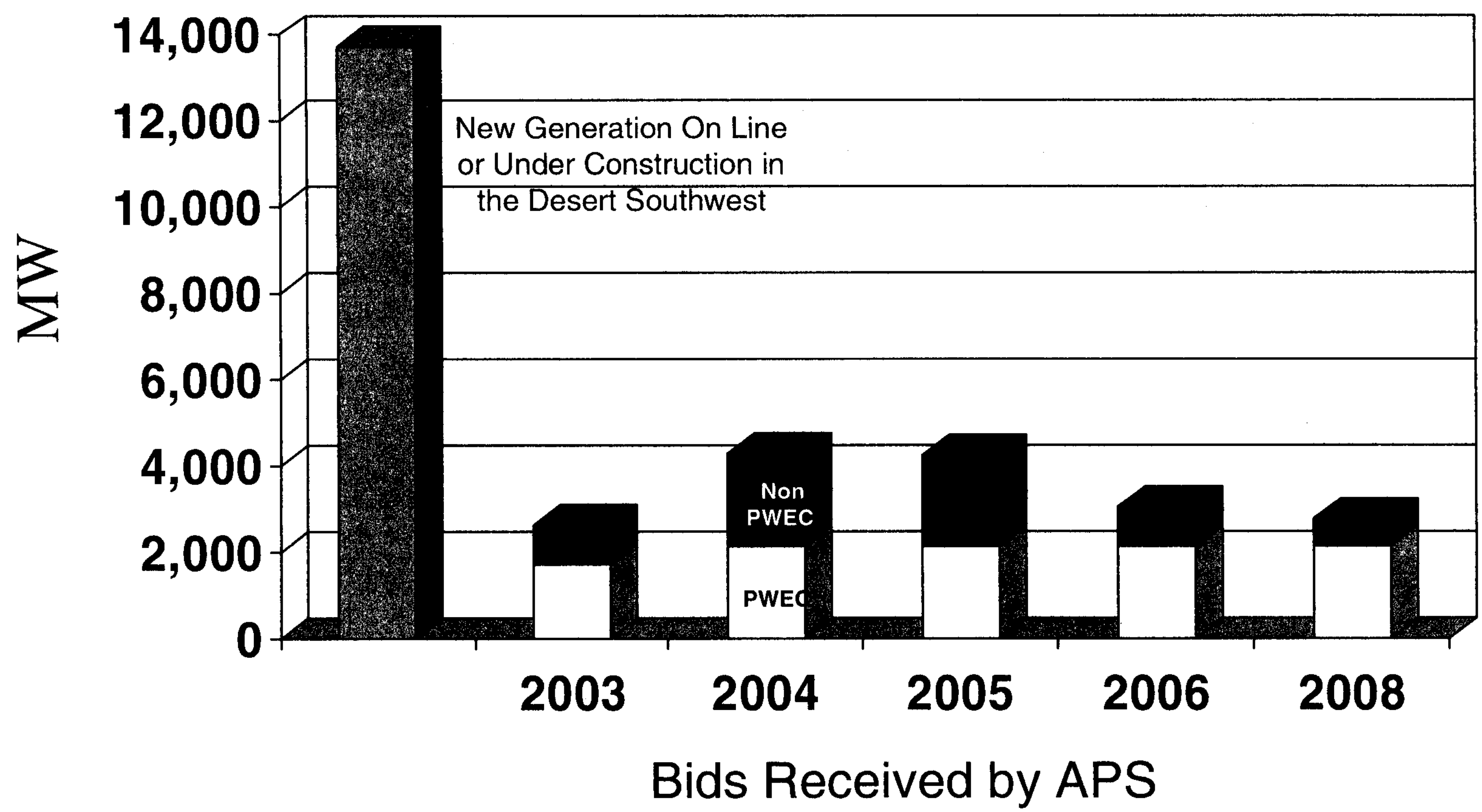
APS SUMMER SUPPLY & DEMAND BALANCE
2003 Long Range Forecast

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	A. LOAD REQUIREMENTS										
	SYSTEM DEMAND										
1	PEAK DEMAND	5,723	6,023	6,269	6,522	6,787	7,064	7,357	7,667	7,914	8,127
2	ANNUAL LOAD GROWTH %		5.2	4.1	4.0	4.1	4.1	4.1	4.2	3.2	2.7
	RELIABILITY										
3	RESERVE REQUIREMENTS	725	787	823	860	898	939	981	1,027	1,062	1,093
4	TOTAL LOAD REQUIREMENTS	6,448	6,810	7,092	7,382	7,685	8,003	8,338	8,694	8,976	9,220
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES										
	EXISTING GENERATION RESOURCES										
5	APS EXISTING GENERATION	3,981	4,007	4,002	4,029	4,029	4,055	4,055	4,055	4,055	4,055
6	SEASONAL VARIATION	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)
7	CAPACITY ON MAINTENANCE	-	-	-	-	-	-	-	-	-	-
8	TOTAL	3,927	3,953	3,948	3,975	3,975	4,001	4,001	4,001	4,001	4,001
	PURCHASED POWER RESOURCES										
9	SRP - FIRM	288	295	302	310	318	326	334	342	351	360
10	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62
11	PACIFICORP DIV EXCH	480	480	480	480	480	480	480	480	480	480
12	TOTAL PURCHASES	830	837	844	852	860	868	876	884	893	902
13	TOTAL EXISTING RESOURCES	4,757	4,790	4,792	4,827	4,834	4,869	4,877	4,885	4,894	4,902
	C. NEW RESOURCES										
14	ENVIRONMENTAL PORTFOLIO	4	10	18	18	21	22	22	23	23	24
15	WP - 4	110	110	110	110	110	110	110	110	110	110
16	WP - 5	524	524	524	524	524	524	524	524	524	524
17	REDHAWK CC 1-2	990	990	990	990	990	990	990	990	990	990
18	SAGUARO SC 3	76	76	76	76	76	76	76	76	76	76
19	PPL's SUNDANCE CTs	112	150	150							
20	MARKET PURCHASE	125									
21	TOTAL	1,941	1,860	1,868	1,718	1,721	1,722	1,722	1,723	1,723	1,724
22	TOTAL EXISTING AND NEW RESOURCES	6,698	6,650	6,660	6,545	6,555	6,591	6,599	6,608	6,617	6,626
	D. TOTAL RESOURCES OVER / (UNDER)	250	(161)	(432)	(837)	(1,130)	(1,412)	(1,740)	(2,086)	(2,360)	(2,594)
	E. OVER / (UNDER) WITHOUT T&C					(1,557)	(1,849)	(2,186)	(2,541)	(2,825)	(3,069)

Non-PWEC Response To APS RFP

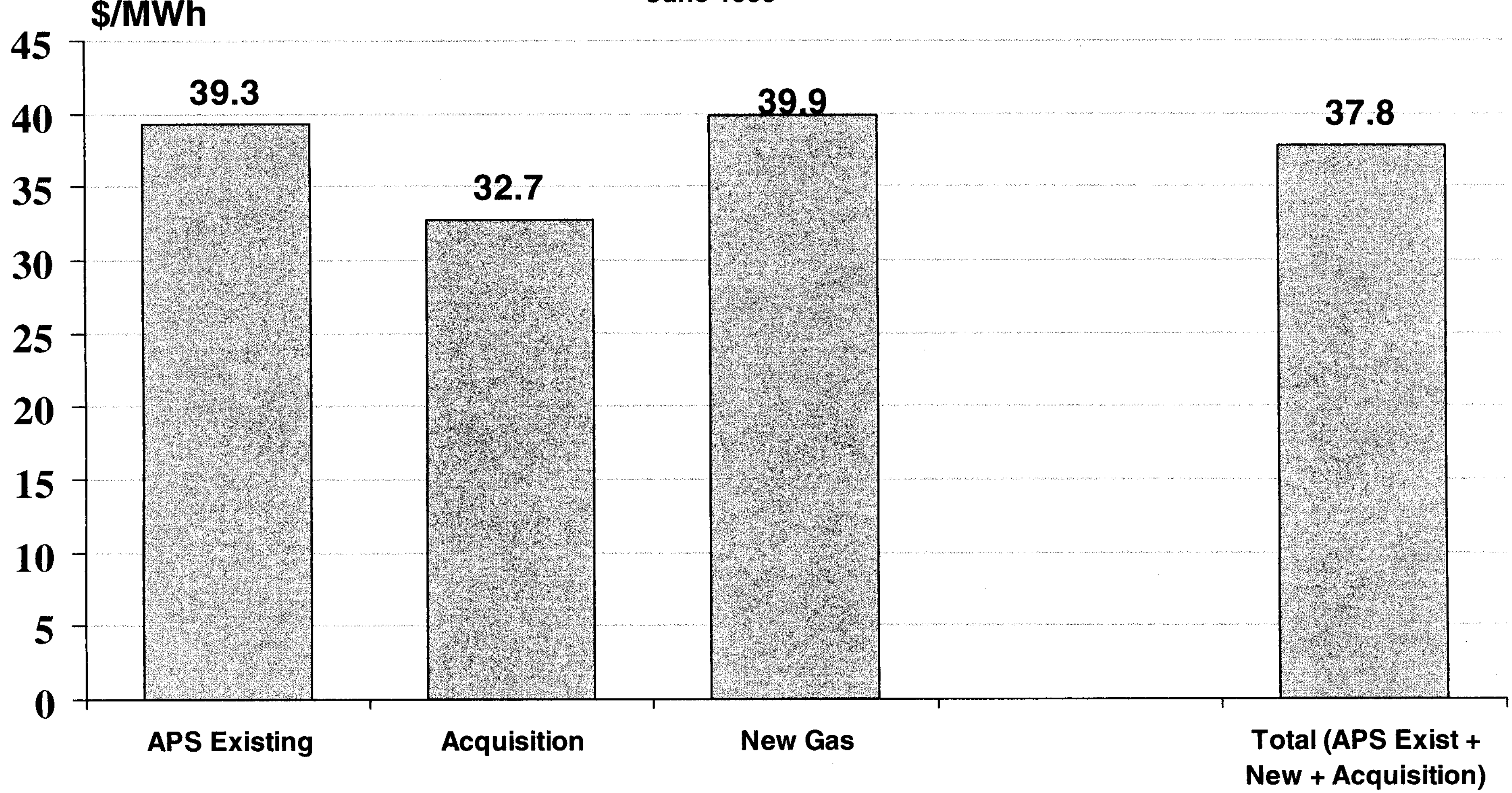


Response To APS RFP



2000-2009 (1999 LRF BUSBAR STUDY)
10-Year Levelized Generation Busbar Cost (w/ Interchange Sales)

June 1999



Redhawk Project Estimated IRR

Study Date	Project In-Service	Const. Cost Estimate $M	Life-time IRR %	Comments
			%	
All Four Units 1-2-3-4				
1/13/1999	02/03/04/05	894	13.7	Initial Planning studies using construction cost data estimated based Engineering judgements.
2/10/1999	02/03/04/05	869	15.2	
2/10/1999	04/05/06/07	904	15.2	
4/23/1999	02/03/04/05	869	16.5	Issued RFP for turbines 8/99. PWEC formed 9/27/99. Board approval and public announcement of project 9/29/99. PCEC permit application 10/20/99
7/1/1999	03/04/05/07	876	16.0	
9/1/1999	03/04/05/07	876	16.5	
11/19/1999	03/04/05/07	1029	15.1	
6/16/2000	02/02/05/06	1128	17.2	Based on studies prepared before and after partnership with Reliant.
8/22/2000	02/02/05/06	1164	18.6	
Units 1&2 Only				
7/3/2001	02/02	566	37.6	Reacting to the California high-market, 4000MW applied for CEC at PV. Redhawk #3 analyzed as CT. $540M committed to Redhawk, $440M cash out by 11/01 .
10/15/2001	02/02	566	13.6	
12/13/2001	02/02	566	15.8	

West Phoenix CC4 Project Estimated IRR

Study Date	Project In-Service	Const. Cost Estimate $M	Life-time IRR %	Comments
4/23/1999	2002	68	6.0	Project announcement 4/23/99.
5/21/1999	2002	70	15.0	IRR based on initial planning studies.
6/25/1999	2001	60	18.7	Project life: 32 year.
9/13/1999	2001	60	16.8	CEC applied 10/4/99.
6/16/2000	2001	75	11.0	CEC received 2/17/00. Final EPC cost estimate: $75M. Construction began

West Phoenix CC5 Project Estimated IRR

Study Date	Project In-Service	Const. Cost Estimate $M	Life-time IRR %	Comments
5/18/1999	2002	220	13.3	IRR based on initial planning studies.
6/25/1999	2002	222	12.6	Project life: 32 years. Partnership
8/10/1999	2002	222	12.6	agreement with Calpine signed 9/99. CEC
6/16/2000	2003	280	15.9	Analysis prepared for 7/00 Board Meeting.
8/16/2000	2002	146	15.3	IRR based on 50% ownership
7/3/2001	2003	280	14.0	Based on 100% ownership after Calpine
10/1/2001	2003	280	12.1	agreement disolved in 01/01. Final EPC
				contract signed 5/01. Construction began
6/24/2002	2003	289	10.3	$116 M cash spent as of 1/02. Cost
9/4/2002	2003	289	14.1	estimate of $289 as of 7/02.
11/4/2002	2003	289	14.9	

Saguaro CT3 Project Estimated IRR

Study Date	Project In-Service	Const. Cost Estimate $M	Life-time IRR %	Comments
7/3/2001	2002	40	23.8	Air permit applied 5/01. Installed temporary 95MW CT @ $18M in 6/01. Turbine cots $23M, total project estimated $40M. EPC contract finalized 7/01. $16M cash
10/1/2001	2002	40	8.7	

APS-8

EXHIBIT

tabbies

APS-8

admitted

TESTIMONY OF WILLIAM H. HIERONYMUS

ON BEHALF OF

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-___

VICE-PRESIDENT

CHARLES RIVER ASSOCIATES INC.

June 27, 2003

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DIRECT TESTIMONY OF WILLIAM H. HIERONYMUS

ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-03-___)

I. QUALIFICATIONS

Q. Please state your name and business address.

A. My name is William H. Hieronymus. I am a Vice President of Charles River Associates Inc. My office address is 200 Clarendon Street, Boston, MA 02116.

Q. Pleases describe Charles River Associates Inc.

A. Charles River Associates Inc. (CRA) is an international economics and managing consulting firm with numerous offices in North America, Europe and Asia. Energy is a major corporate focus. CRA staff focusing primarily on electric and gas utilities, and associated environmental policies, totals approximately 80 people. A like-size group consults primarily on up-stream gas, oil and related chemicals industries.

Q. Please review your own personal background, focusing on those portions relevant to your participation in this case.

A. I am an economist by training, receiving a Ph.D. in economics from the University of Michigan in 1969. After military service, I entered consulting, joining CRA in 1973, primarily to work on major antitrust cases. However, the turmoil in energy industries, particularly the oil price crises of the 1970s, slowdowns in electricity and natural gas demand and related issues, caused me to shift my professional focus to energy economics in about 1975. Principal electricity issues in those days were load forecasting, fuels market forecasting, resource planning, and new forms of rate design and cost allocation to respond to increasing average costs of production.

Continuing into the late 1970s and early 1980s, I continued to focus on electricity and related policy issues. Apart from policy issues such as PURPA and related rate design and renewables procurement issues, the mainstay of my consulting was resource planning, particularly what to do with plants under construction given that the level of load growth was far less than had been anticipated. Indeed, the last case in which I participated that had to do with siting a wholly new utility-owned facility was in 1980. This turned out to be a landmark event in western power markets. Failure to gain regulatory support for building a large coal-fired facility led PG&E and SCE to abandon plans to build any major new facilities. This was a major precursor to restructuring of the electricity industry in California in the late 1990s (state-mandated QF contracts having led to very high power costs) and to the supply-demand imbalance that was the primarily cause of the power crisis in 2000-1.

Much of my utility consulting in the 1980s had to do with the large coal and nuclear power plants that had begun in the early and mid 1970s and were just then coming on line. This led to business issues about what to do with the power, how to control construction and operating costs that seemingly were spiraling out of control and ratebasing issues concerning these comparatively expensive new facilities. I participated in many such proceedings, as well as management consulting analyses of what to do with incomplete plants, including stopping construction altogether or converting them to other fuels.

In 1988, the focus of my activities shifted abroad and to the subject of restructuring electric utility markets. I worked for two years on the restructuring and privatization of the U.K. electricity sector (and subsequently on changes to it) and moved onto restructuring engagements in continental Europe, the Far East and, toward the end of this period, formerly communist systems in Eastern Europe and the U.S.S.R. During this time, I continued some work in this country as well.

I returned to the United States full time in 1993. Since that time I have worked primarily on assignments relating to the restructuring of the North American electricity industry. These have involved the design of power markets, the evaluation of the competitive value of facilities, consideration of merger candidates, various policy issues having to do with affiliate relations, restructuring of companies, the structure of regional markets, market power and market power mitigation, and so forth. A substantial part of my work in the past few years has involved the west coast market. In addition to advising APS and Pinnacle West, I have worked on the SEMPRA merger, the Duke acquisition of Westcoast Energy, the various transactions involving Portland General, the PG&E bankruptcy, and several of the regulatory proceedings involving the California and western power markets, including the FERC cases concerning refunds for the crisis period and the potential cancellation of the power contracts signed in 2001. My resume is attached as Appendix A.

Q. Please describe your relationship with Arizona Public Service and its affiliates.

A. I first came into contact with APS in about 1975 when I was doing research for the predecessor agency of the U.S. Department of Energy, specifically, the development of state-level electricity load forecasting models for use by the agency and state PUCs and planning agencies. I was first retained by APS in circa 1986 to assist in planning for and execution of the Palo Verde Unit I rate case. I worked intermittently with APS, primarily on Palo Verde nuclear plant issues throughout the late 1980s and early 1990s. Subsequent to my return to the United States in 1993, I have worked with the Pinnacle West companies on a variety of strategy issues, most of which have to degree or another dealt with the general area of resource planning. Sometimes, my role has been to provide an independent view and analysis to management. Other times it has been to offer independent advice to in-house staff on methodologies and assumptions. I also have been tasked to review and comment on in-house evolving strategies or pieces of analysis. Sometimes it has been to provide a national or international view of trends and developments to management. In this context, I have had a semi-continuous familiarity with the resource planning tools and analyses of APS and Pinnacle West.

I also have testified on behalf of the companies on a number of occasions, most recently including Docket No. E-01345A-98-0473, et al; the settlement case in which it was determined that APS generating assets would be transferred to what became Pinnacle West Energy Company (PWEC); and also Docket No. E-01345A-01-0822 in which PWEC and APS sought to establish a full requirements PPA between the two companies. This latter proceeding subsequently was merged into and ACC Docket E-00000A-02-0051, referred to as the "Track A" proceeding in which I also testified.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony relates generally to the question of whether the Pinnacle West investment in the Redhawk, West Phoenix and Saguaro units properly is included in APS's ratebase. The standard that I will employ is the "prudent investment test". At the core of the test is the question, was the investment prudent in light of what was known or reasonably knowable at the time that it was made? In this context, I review the options available to Pinnacle West[1] for meeting APS's customers' needs. As a closely related matter, I have reviewed, and provide an independent commentary upon, Pinnacle West's resource planning and evaluation, particularly as it relates to the "reliability assets" – West Phoenix 4 & 5, Saguaro and to Redhawk. I also will discuss whether these assets are and will be "used and useful" in meeting APS's load. Finally, while I do not believe that an analysis of the contemporary economics of the PWEC Arizona generation, as opposed to one that is based on the prudence of the investments when made, is appropriate for evaluating the inclusion of these assets in APS's ratebase, I will discuss the likely economics of the acquisition. In part, my discussion on this point will review what

[1] Generally, I will use the term "Pinnacle West" to refer to Pinnacle West Capital Corporation, the parent of both APS and Pinnacle West Energy Company (PWEC). In some cases, operative decisions were implemented at one subsidiary or the other. However, Pinnacle West Capital had fiduciary responsibilities for the entire enterprise, including both subsidiaries and also had ultimate responsibility for the conduct of the utility functions of APS regulated by this commission. Where referring specifically to either APS or to PWEC, I will use those terms. In discussing planning functions, I also will refer to Pinnacle West for the simple reason that planning functions sometimes were wholly in APS and sometimes were split between APS, PWEC and Pinnacle West corporate.

was learned in the "Track B" process about third party resources that might be available to meet APS's load in the future.

Portions of this analysis compliment the testimony of Mr. Ajit Bhatti, who testifies in some detail about many of these same matters from the perspective of being the person in charge of resource planning for the company, both now and during the period when the PWEC assets were planned and constructed.

Q. Please summarize your conclusions.

A. I conclude that the investment in West Phoenix, Redhawk and Saguaro was prudent. The concept of prudence requires that management's decisions and actions were reasonable given what was "known or knowable" at the time. This standard is met readily with respect to these plants. Indeed, I conclude that Pinnacle West management could not prudently have avoided building these facilities, a far higher standard of prudence than ever has been applied to an electric utility.

As I will discuss, these plants were built as part of an "APS-centric" decision process that focused on assuring that APS's native load could be met reliably and at reasonable costs. The APS-centric planning process was warranted because Pinnacle West had a corporate obligation to APS and its customers. Ordinarily, the result would have been that APS would have built or otherwise acquired capacity itself. This was precluded by the Electric Competition Rules. Instead, it was necessary for another Pinnacle West subsidiary, Pinnacle West Energy Company (PWEC) to build the units. This concern with APS dictated the location of the plants and the timing and amount of plant additions.

There can be no dispute that the type of plants that were built, gas combined cycle and simple cycle units, was a prudent choice since these same plant types account for virtually all new construction. The amount and timing of new construction also was prudent. West Phoenix construction was commenced when it became clear that new capacity was needed to meet the needs of the Valley load pocket. No merchant had announced plans to build capacity within the load pocket (and none are planned now). The West Phoenix additions were planned to come on line when needed; their schedule was appropriate even with the benefit of hindsight. Indeed, without West Phoenix 4 coming on line in 2001, it is unlikely that APS could have met load without curtailment or other emergency measures.

The Saguaro unit was planned to meet load economically in the anticipated shortage conditions of the summer of 2002. Without it, APS would have had to take measures similar to those taken in the summer of 2001, which would have been substantially more expensive than the annualized cost of Saguaro.

Redhawk was planned as a flexible future addition to meet load in the first decade of the new millennium. Its timing was firmed and contracts were signed in 1999 in response to unanticipated load growth being experienced in the latter half of the 1990s and in recognition that new merchant capacity was slow to build in Arizona and not reliably available to meet APS's load. It was accelerated in 2000 to the schedule on which it was built in response to still more load growth in the early summer of 2000 and to the beginning of the western electricity crisis. Until well past the time when the investment was irrevocably committed it would not have been reasonable for APS to rely on generation being built by others for the market to meet its load at prices no higher than the cost of construction. Even in the Track B solicitation, long after the electricity crisis had waned, only quite modest and insufficient amounts of generation owned by others was made available for contracts to meet APS's load.

I also reviewed APS's planning process and management decisions over the period that is relevant to a prudence inquiry. I found that the process was highly professional and, as already summarized, the decisions were prudent and intended to assure that APS could meet load reliably and economically. There were no infirmities of either the resource planning methods or decisions that, if cured, would have caused Pinnacle West to have not built these units.

I also reviewed the construction costs of the PWEC Arizona units and conclude that their costs were in the middle of the range of costs for similar units, as best as can be ascertained from publicly available data. Given the biases in those data, I conclude that the Pinnacle West units likely were below average in cost. Hence I conclude that the management and execution of construction also was prudent.

The PWEC assets also are "used and useful" to meeting the APS load. Indeed, they have been so since coming on line. Effective July 1 of this year, they will be dedicated by contract to meeting APS's summer loads. Based on current forecasts, APS will be short, notwithstanding these contracts, by the time rates decided in this proceeding are effective. APS will continue to need capacity (beyond its owned capacity) in amounts greater than these assets in all years thereafter.

My testimony also looks forward at power markets during the period after the rates set in this proceeding come into effect. While I do not believe that such an analysis should be central to this proceeding, I recognize that the likely economics of ratebasing the assets may be of interest. Over most of the future, the Pinnacle West assets are essentially certain to be cost effective since market prices will vary around long run, marginal cost, essentially the cost of a new and similar unit. Unlike the PWEC units, the units that set long run marginal costs will be built with future and more inflated dollars that are not depreciated. Hence, there is a predictable, continuous wedge of benefit from ratebasing the units. In the nearer term, rate-basing the units might be more expensive than the market as a result of the price-depressing effects of the new capacity coming on line in 2002-2003. However, the "glut " period likely will be very brief. Western power markets will cease to be in surplus, most likely beginning sometime between 2005 and 2008. My best estimate is for 2007. In view of the "boom-bust" nature of power markets in particular, and commodity markets generally, I do not expect that a new age of capacity/load balance will be reached without another period of near-shortage and resulting high prices. Indeed, my testimony will explain the inevitability of such cyclic price spikes as were seen in 2000-2001 in the operation of competitive power markets and the necessity of price spikes to the economics of building new generation plants for the market. My expectation of a near-shortage and price spike in the latter half of the decade, which occurs essentially at the same time that the Track B contracts will expire, is amplified by knowledge of the reduced circumstances of the merchants that built the majority of new capacity over the past three years and the continuing regulatory difficulties they are experiencing in being paid for long term contracts and other sales in Western power markets.

For these reasons, I conclude that ratebasing these assets is likely to be cost-effective, relative to purchasing from the competitive wholesale market, for APS.

Q. How is your testimony organized?

A. Section III discusses the regulatory concept of "prudence," the test that I believe is central to the ratebasing of these assets. Section IV analyzes the prudence of decisions to construct the PWEC Arizona assets. Section V summarizes my review of APS's system planning in the relevant period, drawing substantially on studies addressed in the prior section. Section VI presents the results of benchmarking the cost of the PWEC units against the cost of other units built during this period. Section VII addresses the issue of whether the PWEC assets are used and useful to APS's customers. Section VIII discusses lessons learned from the Track B procurement. Section IX assesses near-term forward markets, and in particularly the likely timing and magnitude of the next price spike. More generally, it provides qualitative information that supports a conclusion that ratebasing the PWEC assets is likely to result in lower and less volatile prices than relying on the market for the same amount of electricity. Section X briefly summarizes my main conclusions.

<u>III. The Concept of Prudence</u>

Q. Please define what is meant by prudence in the context of utility regulation.

A. As a general matter, the use of the term "prudence" refers to costs incurred by regulated utilities. Most commonly, it is applied to tangible investments made by the utility, though it also can be applied to other costs, such as costs for power contracts. The concept of "prudent investment" relates to the utilities' ability, and right under the form of regulation that has applied to utilities for at least the last 50 years, to include the prudently incurred cost of investments in ratebase and have a reasonable opportunity to earn a fair return on the investment.

The definition of prudence contained in the regulations of the Arizona Corporation Commission (A. A. C. R14-2-103) is characteristic of the term as used in other jurisdictions as well. The definition is:

> "Prudently invested" – investments which under ordinary circumstances would be deemed reasonable and not dishonest or obviously wasteful. All investments shall be presumed to have been prudently made, and such presumptions may be set aside only by clear and convincing evidence that such investments were imprudent, when viewed in the light of all relevant conditions known or which in the exercise of reasonable judgment should have been known, at the time such investments were made."

The key elements of the definition are: (1) the strong presumption of prudence; (2) the clear deference to management decision making implied by the notion that imprudent investments are those that are dishonest and obviously wasteful; and (3) the exclusive focus on what was known or reasonably knowable at the time that decisions were made -- not at the time of a ratebasing decision or at any other future date. The limitation of the analysis to focus on what was then known or knowable means that "20-20 hindsight" is not permitted or appropriate. Some decisions that were prudent may well turn out to be sub-optimal from a later perspective. Others may, with similar hindsight turn out to be particularly beneficial. I note also that the focus on reasonable judgment means that "prudence" does not mean "perfection" but merely that the decision or actions could reasonably have been made by competent decision-makers.

The relevant time frame for considering prudence, in this instance, is short. Significant financial commitments to the units began only in 1999, and by no later than early 2001, the decisions concerning construction of these units were irrevocable, in that (1) no other timely resource was available to reliably meet load on a timely basis and (2) construction expenditure was so far advanced that cancellation was not an economic option. During that period, Pinnacle West:

- Could not reasonably have relied on the expectation that enough merchant capacity would be built on a timely basis to meet APS load beginning in January, 2003.
- Would not reasonably have anticipated the extent of the collapse of power prices in the second half of 2001.
- Would not reasonably have anticipated that the ACC would unilaterally modify the settlement and prevent PWEC's acquisition of APS's existing assets.
- Would have recognized that no merchant capacity was being built to serve APS's load, particularly to support reliability in the Valley load pocket.

IV. THE PRUDENCE OF CONSTRUCTING THE RELIABILITY ASSETS

Q. Please summarize your conclusions concerning the prudence of constructing the Red Hawk, West Phoenix and Saguaro units.

A. Essentially, I reach two conclusions. First, the construction of the new units that APS is seeking to include in ratebase was prudent. That is, the decision process whereby APS's affiliates committed to the units was at all times reasonable, indeed was quite appropriate even viewed with hindsight. Further, I demonstrate that the cost of the units was reasonable in comparison to similar units constructed at about the same time by others. My testimony demonstrates that it was prudent for Pinnacle West to build the units in anticipation of the fulfillment of the Settlement Agreement – either as part of a merchant portfolio eligible to compete to supply APS's load or as units that would be dedicated to APS under an A.C.C.-approved contract. I also demonstrate that Pinnacle West, acting as APS's parent, was prudent in building sufficient resources to enable it to meet the substantial majority of APS's load, notwithstanding the provisions of the Electric Competition Rules, in view of the evolving circumstances that became inconsistent with the market development expectations that the Electric Competition Rules and Settlement were predicated upon. Indeed, in view of what was then known or knowable, it would have been derelict for Pinnacle West not to have done so.

This leads me to my second point. The decision to build the units was "APS-centric". While Pinnacle West was fully aware of the fact that generation was to be severed from APS, and that the Settlement required that APS purchase its energy and capacity from the competitive wholesale market, Pinnacle West used its generation subsidiary to build or otherwise acquire the capacity that would be needed to meet APS's load. The location of the Pinnacle West units, the integration of them with new transmission to reach the rapidly growing Valley load center, the acceleration of their commercial operation to match load growth forecasts for APS and the deliberate decision to not contract the capacity on a long term basis to California or Nevada all point to the fact that Pinnacle West's capacity expansion plans were driven by APS's needs.

This does not mean that Pinnacle West proceeded without regard for the provisions of the Electric Competition Rules. Indeed it was because of those rules that it was compelled to act as it did, *i.e.*, to have necessary assets built outside of APS. At relevant times, Pinnacle West had valid concerns as the owner of APS that non-PWEC capacity would not be available on a timely basis, in sufficient amounts, or at economic prices, to meet APS's load. Moreover, its studies demonstrated that the PWEC portfolio, inclusive of transferred and new assets, would have below market costs and would have been able to compete successfully for as much of the APS portfolio requirement as it chose to serve in 2002 and beyond. In fact, I have reviewed planning studies executed in 1999, the year that West Phoenix and Redhawk were announced and initiated, that assumed, consistent with the Settlement agreement, that all PWEC generation would be sold at no higher than market prices, but also demonstrated that this low cost competitive position would enable PWEC to be the successfully bidder for 100 percent of APS's load requirements.

Because I will conclude that Pinnacle West had no prudent alternative to building the capacity required to meet APS's load and all of the generation at issue was built to serve that load, I have looked at the prudence issue in the same way that I would have assessed prudence if APS still were a fully integrated utility and had built the units itself. That is, rather than looking at prudence from the perspective of PWEC building an integrated portfolio to serve the market, I have looked at the resource planning decisions from the perspective of whether they were a prudent basis for planning to meet APS's load. This is a more stringent test.

Q. **How have you examined the issue of whether construction of these assets was prudent?**

A. I have focused primarily on planning decisions and studies in the late 1990s and the 2000-2001 period. This is the period during which the commitments to build the PWEC generation were made. It encompasses also the period during which the decisions theoretically might have been reversed based on what became known or knowable after construction was initiated. I will refer to the prudence of decisions to build the units as "planning prudence." As a separate matter, I also consider the cost of these units in comparison to other similar units in order to determine whether the units were prudently constructed. I will refer to the reasonableness of the construction cost of the units as "construction prudence."

In assessing decisions to build the units, I have reviewed numerous planning studies. Many if not all of the key studies that I will reference are discussed in Mr. Bhatti's testimony. I also have relied on my own quite substantial knowledge of what was happening in the electricity industry in the west and in the United States generally during this period. To some degree, I also have relied on discussions that I had with Pinnacle West planners and executives during this period.

Q. **How will you address the planning prudence issue?**

A. In considering whether it was prudent for APS to build these units, keeping track of the chronology of events is critical. In the late 1990s, Pinnacle West found itself in a unique position as a result of the ACC's Competition Rules and the Settlement. On the one hand, APS (and hence Pinnacle West) had an obligation to serve the needs of APS's full requirements customers reliably and economically. On the other hand, APS itself was forbidden to acquire new generation.[2] Indeed, it was anticipated that APS would, by the end of 2002, no longer control its then-existing generation.

Had the situation evolved as anticipated at the time of the Competition Rules in 1998 and 1999, this mismatch between APS's responsibilities and its authority might not have been a problem. Prior to and into that period, APS anticipated that there would be ample low cost power available in the West that it could purchase on a short-term basis to meet its requirements through at least 2004. Moreover, retail access was expected to result in a reduction in those requirements, albeit by an unknown amount. Neither APS's forecasts, nor any other forecasts of which I am aware, indicated a need to secure new capacity after 1998 prior to the end of 2002 when the asset transfer was due to take place.[3] Since new long term capacity commitments were not believed to be needed before 2004 at the earliest, even as late as the 1999 version of the Competition Rules, this may explain why there was no provision in either the Electric Competition Rules or the Settlement dealing with securing new supplies prior to 2003.

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[2] During most of this period, it was assumed that the fossil generation would be transferred by the end of 2001 and the nuclear generation by the end of 2002.

More generally, the spirit of the Competition Rules was that the market would provide. Certainly in 1998, and even in 1999, there appeared to be an expectation by the ACC that the market would provide capacity sufficient to meet APS's needs.

Q. When did the expectation that APS would need no new resources before 2004 begin to erode?

A. By about 1998 it became clear to APS that its load growth and growth for other load serving entities in the Desert Southwest, and to a lesser extent growth in the WECC generally, was very substantially exceeding expectations. This concern deepened in 1999. As a result, future regional reserve margins that APS had forecast to be ample until at least 2004 began to shrink rapidly. Moreover, experience in states that were early adopters of retail access suggested that APS would retain a need to serve substantially its entire load. Moreover, little new capacity had been announced for Arizona and most of that appeared to be destined for California. Despite AB1890, which in 1996 had restructured the California market, attempts to build new capacity in that market were stalled by siting and environmental permitting difficulties.[4]

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[3] For example, the 1999 WSCC 10-Year Plan still showed that the WSCC as a whole would be reserve adequate even under adverse hydro conditions through 2005 and the Desert Southwest region through 2004.

[4] The California Energy Commission's database of new and planned generation in the WECC (http://www.energy.ca.gov/electricity/wscc_proposed_generation.html/download) shows only 59 MW of new generation (all of it geothermal) built in California in 2000, four years after AB1890. In 2001, about 2,600 MW of new generation came on line in the state, most of it after the crisis had passed and the majority of it being quickly built peaking units, many of which were commissioned as a result of actions by the state, the California ISO and California Department of Water Resources in response to the 2000-1 crisis.

clear that new capacity would be needed substantially earlier than had been anticipated. New capacity would have to be secured to serve APS's load even if the Valley reliability constraint was met by the West Phoenix units.

Merchant plants were not a demonstrated solution. By the end of 1998, more than two years after AB1890 and Arizona's first restructuring order, only three merchant units totaling approximately 1,600 MW had been announced in Arizona. It should be emphasized that these were announcements only. Experience shows that less than half of announced merchant projects (more typically, one-third) actually are constructed in the general timeframe originally contemplated. Moreover, two of the three projects were sited in northwest Arizona, off of APS's transmission system, and clearly intended for the California/southern Nevada markets.

APS's own studies indicated that California and southern Nevada would be higher priced markets than Arizona and therefore more lucrative markets for merchant generators to build in or sell into. Thus, it was not clear that the market would provide sufficient capacity to meet APS's needs in the early part of the new century. By the spring of 1998, APS's deficiency was projected to be approximately 1,200 MW by 2002 and the decision to build West Phoenix would cover only half of this.[5] The 1998 system plan (which did not yet include West Phoenix) still reflected a reliance on future market purchases to meet that need. However, confidence that the market would continue to have a surplus sufficient to

[5] The 1995 IRP showed a deficit of 200 MW in the year 2002. The 1997 Loads and Resources Forecast increased the 2002 load forecast by approximately 530 MW, implying a further generation need of

economically and reliably meet that need was eroding. The 1998 summer peak turned out to be 400 MW above the then-current forecast; SRP had similar load growth. This implied a further shortfall in the early-2000s, not merely for APS but for the whole region. Partly for that reason, and partly to support its role under the Settlement as an unregulated generator, Pinnacle West performed numerous planning studies in 1998-1999 to consider options for meeting APS's load and creating a balanced portfolio for PWEC.[6]

Q. Do Pinnacle West's planning studies at that time indicate an unwillingness to rely on the market for new capacity?

A. No. As I stated, APS, as of early 1998, had determined that it remained prudent to rely on the existing surplus of generation in the WECC to meet up to 1,000 MW of APS's load requirements through 2004. For new generation, the assumption quite properly was that the cost of power production for PWEC and the cost of new wholesale contracts for APS would be essentially the same, whether PWEC or some other vendor was the source. However, new generation, whether purchased via contract or produced by PWEC, was not the preferred option. Pinnacle West's preference was to buy available shares of existing Arizona baseload units rather than to build new capacity itself. Its belief and expectation was that shares of these units could be purchased at more economical prices than generation from new units. Further, in view of the fact that all new generation for the foreseeable future was expected to be gas, buying shares of existing coal and nuclear units was a

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approximately 600 MW. The load forecast for 2002 increased by a further 400 MW in the Spring of 1998. Note also that then-current plans were that West Phoenix 5 would be fifty percent owned by Calpine.

limited and disappearing chance to increase the non-gas share of generation supporting APS's load. Owning coal and nuclear units would become increasingly economic if Pinnacle West's expectation of higher gas prices was borne out.

Q. **Did Pinnacle West actively pursue buying additional shares of existing generation?**

A. Yes. APS had negotiated an agreement to buy generation from TEP that was part of the failed three-way settlement in 1998. In any event, the TEP purchase would have carried with it a contractual requirement to serve TEP's load, so this would have done nothing to cure APS's shortfall in the near term. Planning documents indicate that APS considered buying LADWP's share of Palo Verde, but those discussions went nowhere. Promising discussions were entered into with El Paso Electric (El Paso) and Southern California Edison (SCE) concerning acquisition of their shares of Palo Verde and Four Corners. It was believed that these plants would allow Arizona load to be met though the early years of the new century.

Q. **Did Pinnacle West's planning presume that all potential purchases of shares in existing jointly owned units could be used to meet APS's load?**

A. No. Planning studies indicate that any purchase from El Paso Electric would entail a power buyback through at least 2004. Moreover, transmission limitations from Four Corners meant that not all of SCE's share of that unit could serve APS's load, even if SCE's transmission rights were purchased. Hence, at most 1,000 MW of

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[6] Until at least late 1999, these studies were performed by APS, since the Pinnacle West resource planning function at this time still was wholly within APS.

the purchases could be used to serve APS's load prior to expiration of any buy back contract with El Paso.

Further, there never was any firm assurance that either of the purchases would be executed, as indeed, they were not. The El Paso negotiations, in particular, never even reached a Memorandum of Agreement stage. Moreover, neither of the purchases would serve APS's need for in-Valley generation. Redhawk and the purchases were simply elements of a portfolio of options that Pinnacle West was pursuing to serve APS's load and provide a basis for off-system energy sales by PWEC.

Q. When did building the Redhawk units enter into Pinnacle West's planning?

A. Studies conducted in 1998 indicated that it would be feasible to site up to 2,000 MW of gas-fired plant at or near Palo Verde. By early 1999 longer range generation plans focused on building combined cycle plants at Palo Verde, totaling up to 2,000 MW. Notably, building new capacity at Palo Verde was planned to coincide with APS building additional transmission capacity into the Valley. Hence, by design, all of this generation was capable of being used to serve APS load. Similarly, in pursuing negotiations with SCE over its Four Corners share, Pinnacle West also sought to acquire SCE's transmission rights that would enable the acquired generation to be accessed by APS's load. Hence, both the construction and purchase options were designed to enable the company to support APS's requirements.

Q. **Is there any particular point in time that you can identify when a critical decision was made concerning Redhawk versus the attempt to purchase shares of existing assets?**

A. Yes. Expenditure on Redhawk began in the spring of 1999, albeit at a low level. By autumn, Pinnacle West faced a decision concerning executing the engineering and construction contract. Once that agreement was executed, the cost of withdrawing from, or substantially delaying Redhawk would increase rapidly.

In parallel, Pinnacle West was negotiating with SCE and El Paso. While the SCE Memorandum of Understanding was not executed until April 2000, and no agreement ever was reached with El Paso, by that same time Pinnacle West had a reasonably firm idea of what would be the agreed purchase prices.

Pinnacle West studies showed clearly that, at the expected prices, the SCE and El Paso option was economically superior to the market – i.e. to the cost of new combined cycle capacity, whether built by it or someone else. Hence in the fall of 1999 it faced a dilemma. On the one hand, it needed to "fish or cut bait" on proceeding with immediate construction of Redhawk. This decision needed to be made while it still was uncertain whether the SCE and El Paso negotiations would ultimately prove successful. If the decision to go ahead with Redhawk was made, and the negotiations with both parties proved successful, the corporation would be substantially long in the market. Conversely, if Redhawk did not go ahead, and the negotiations failed, APS load would be dangerously unhedged and potentially unmet. This set of risks led to a major study dated September 11, 1999.

Q. **Please describe the September 11, 1999 study.**

A. There are several notable things about this study. First, it indicates that if all of these plans came to fruition, Pinnacle West would be long in power markets. Second, the study assumed that PWEC would serve 100 percent of APS load in that sales equal to APS's load were assumed dedicated to APS throughout the study period. Third, the base case for the study assumed, consistent with the facts as then known, that relatively modest amounts of new generation would be built by merchants in the relevant period. Both the Desert Southwest and California remained short, California alarmingly so. Fourth, the study did an excellent job of investigating the sensitivity of results to key drivers of the market. These included gas prices, water levels for hydro generation, the amount of new builds, and the possibility that major existing units for which closure was being discussed (principally, the West Coast nuclear units and Mojave) would in fact be closed.

Based on study results, the acquisition of the shares of Palo Verde and Four Corners was both the lowest cost action and provided the best hedge against rising gas prices. Indeed, it was shown to be more cost-effective than Pinnacle West's then-existing APS generation, primarily because it was believed that SCE's Palo Verde share could be acquired at substantially below book value. The PWEC new builds had forecasts costs essentially identical to the generation inherited from APS.

In short, the study showed that both main elements of the possible expansion of generation were cost-effective against market alternatives and that the fuel mix provided a useful hedge against known gas price uncertainty and potential uncertainty concerning the future operating performance of nuclear and baseload coal units.

Q. You stated that the Pinnacle West study assumed that PWEC would supply 100 percent of APS's needs. Wasn't that inconsistent with the Electric Competition Rules?

A. No. The Competition Rules required that APS procure 100 percent of its requirements from the market and the Settlement Agreement (which already had been signed) specifically allowed sales to APS from an affiliate as "in the public interest." It did not limit the amount that affiliated companies could sell to it at prices no higher than the market price. At the time of the study, Pinnacle West believed that the "all-in" cost of its fleet of generation taken as a whole (including both purchases and new builds as well as the generation transferred from APS) would be below the market price. It also believed that little if any generation local to Arizona would be available to compete to serve APS's load, at least in the near term. Finally, Pinnacle West management remained committed to meeting APS's needs with resources that it controlled. The analysis I have been discussing explicitly compared the cost of the PWEC fleet and its main components to the cost of generation from a generic new combined cycle unit and concluded that the PWEC fleet as a whole would have a significant cost advantage. Also, Pinnacle West's studies showed that California would need to import more generation than it believed would be built in the Desert Southwest or, equivalently would demand a price higher than the price PWEC would need to receive in order to earn a capital market-required rate of return on sales to APS. Hence, Pinnacle West's belief that

PWEC could profitably outbid such other suppliers as choose to compete to serve the load was eminently reasonable and consistent with the Competition Rules.[7]

I should note that, in one sense, it did not matter that Pinnacle West assumed that PWEC would serve APS's load. From an enterprise risk management perspective, the key fact was that APS would in 2003 be more than 6,000 MW short against the market since it no longer would own any resources. Thus, APS was fully exposed, on both a price and reliability basis, to the market. While APS needed to be hedged, its short position was essentially offset by PWEC's long position. Viewed solely from the perspective of corporate-level economics, the same potentially short market that would injure APS and its ratepayers would benefit PWEC in essentially a like manner. The fact that Pinnacle West planned and executed an expansion strategy geared to meeting APS's needs demonstrates that its focus was on APS, not merely on the overall corporate bottom line.

Q. **So is it your testimony that Pinnacle West was comfortable being long against the market by the approximately 2,000 MW that were shown in the study?**

A. No. First, I should note that Pinnacle West did not expect to have use of the output from the El Paso units for some time, as there were commercial and regulatory imperatives facing El Paso that meant that the power likely would not be available to Pinnacle West until 2005. Also, in parallel to the analyses of potential expansion of owned generation, Pinnacle West also was looking at partnering arrangements.

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[7] I use the term "profitable" here as it is used by economists, not in its accounting sense. Economic profitability is profits in excess of full costs, including a return on the equity portion of capital, whereas an asset is profitable in the accounting sense if it makes any equity profit at all. Note too that while sales at below-market prices could be profitable in this sense, they still were not profit-maximizing since selling at market prices would be still more profitable.

My recollection is that there were three reasons for such negotiations. First, it intended to use the joint ventures to enhance its skills in carrying out the planned expansion. Pinnacle West sought a joint venture relationship with Calpine because Calpine was a large scale and highly reputable power project developer. It sought a relationship with Reliant because Reliant was a highly experienced marketer of both electricity and gas. Pinnacle West thus sought to partner with entities that brought skills to the bargain that complemented and supplement Pinnacle West's abilities.

Second, Pinnacle West sought to reduce its long position, notwithstanding that it appeared from its studies that a long position would be profitable. The Calpine and Reliant ventures involved partnering arrangements that, effectively, divested half of Redhawk 1 and 2 and half of West Phoenix 5, a total of nearly 800 MW.[8] This substantially reduced the potential long position, particularly for the first several years. I should note that part of the Reliant deal was a swap. However, the swap was less than megawatt-for-megawatt and diversified market exposure within the WSCC.[9]

Third, there was no assurance that both or either of the SCE and El Paso negotiations would succeed. The failure of either would substantially eliminate the long position. Pinnacle West's "supply plan" as of the fall of 1999 can best be thought of as a group of options that were being pursued to ensure that APS needs

[8] Note that the fact of the joint ventures did not limit the output from the Redhawk and West Phoenix units that could be made available to APS. However, Calpine and Reliant were under no obligation to offer their output to APS.

still could be met even if some of them failed to be feasible or if circumstances differed materially from plan. Redhawk was the "fly wheel;" timing of it was being managed to compensate for, and balance, changes in the more favored program of purchasing shares of existing generation.[10]

Q. Please continue through your time sequence. What happened subsequent to September 1999?

A. In the fall of 1999, Pinnacle West signed the EPC agreement for Redhawk and announced it to the public. I hesitate to say that this was now a "committed" investment since for an increasingly steep price it could be unwound. For example, by the end of 1999, cancellation costs had risen to approximately $200 million.

An agreement in principle to buy SCE's share of Four Corners and Palo Verde was entered into in April of 2000. By this time, the negotiations to purchase El Paso generation had failed to produce a positive result. Under the SCE agreement, SCE had an opportunity to "shop" the bid to other buyer, so the purchase remained uncertain.

As the California crisis began in early May 2000 and continued through the summer (and beyond), Pinnacle West came to regard the SCE purchase as increasingly unlikely. First, as forward prices rose, the likelihood that an alternative buyer would emerge who would outbid the MOU price by an amount

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[9] By the time that the joint venture arrangements were terminated in early 2001, APS needed the capacity that was released. Moreover, eliminating the swap deal with Reliant better focused the geographic position of the PWEC assets on APS.

[10] For example, a planning study early in 1999 provided for building one Redhawk unit per year starting in 2002 if the purchase of SCE's shares did not occur, but delaying the schedule by two years if it did. A one-year delay also was modeled. At the time of announcement in fall, 1999, the schedule was to build the first unit in 2003 and the second in 2004.

that Pinnacle West would not match increased substantially. Pinnacle West's attitude toward acquisitions that were not clearly tied to APS's load was cautious as a general matter, as demonstrated by its hesitant posture toward purchasing the California fossil assets divested by that state's IOUs, and it was unlikely that they would outbid the most optimistic alternative bidder in a suddenly bullish market for the SCE assets. Second, as the California utilities, including SCE, piled up billions of dollars in unrecovered power costs as a result of being under-hedged, it became increasingly likely either that SCE itself would end the sale or that the California government and regulators would not permit still further divestiture that would remove the (inadequate) hedge against the short term market that SCE still retained. Hence, the SCE deal at the desirable negotiated price became increasingly speculative.

Ultimately, the SCE's Four Corners share was bid away from Pinnacle West.[11] The agreement to buy the share of Palo Verde survived on paper until the beginning of 2001, when the California legislature forbade California utilities from selling any of their generation.

Q. **Moving beyond the events of September 1999, please take up again your chronology of what was happening with the Pinnacle West companies.**

A. During 1999, the negotiation and ultimate acceptance of the Settlement meant that, by the end of 2002, APS's existing generating assets would be consolidated into

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[11] While SCE did not formally inform Pinnacle West that its bid had been topped (by a quite substantial margin) until nearly the end of 2000, it earlier had signaled that superior offers were being negotiated. Well before the end of 2000, Pinnacle West had resigned itself to the likelihood of such an event. In any event, the matter was moot since it was by then highly likely that California would not permit the asset sale to take place, as was soon thereafter confirmed by legislative action.

PWEC. Studies were performed to determine whether the combined assets, including both the assets to be purchased from SCE and new gas-fired generation at West Phoenix and Palo Verde, would be competitive at market prices. It was determined that they would be. In part this was due to the lower costs of the existing assets and the SCE assets relative to new combined cycle units.

In the fall of 1999, Pinnacle West announced the Redhawk project with units 1 and 2 planned to come into service in 2003 and 2004. The last four months of 1999 saw several other new plant announcements by other generators. Again, there was no assurance that all, or indeed any, of these units would be built (indeed, it was quite unlikely, based on historic experience) or even if built would be made available to meet APS's load. None of the merchant units began construction until the late winter of 2000-2001, well into the Western electricity crisis. Significantly, none of the new merchant units (i.e., other than SRP units) were sited to meet Valley reliability requirements.

The sudden rush of plant announcements in late 1999, before the run-up of prices in Spring, 2000 demonstrates that Pinnacle West was not alone in forecasting that power supplies in the WECC would soon become very tight. No similar spate of announcements was seen in California, the most power deficient region, however. A major contributing factor to the geographic distribution of new announcements doubtless was the continuing inability to site plant in California. In contrast, Arizona presented a relatively efficient and feasible permitting process. With substantial transmission available between Arizona and California, these plants (most of which were clustered around the strong Palo Verde hub) would have opportunities to trade into, and transmit power to, California.

Q. What happened in 2000?

A. Moving into 2000, none of the new facilities announced in 1999, except for West Phoenix 4 and Redhawk, actually began construction until 2001. With relatively little invested in these new facilities, a shakeout reasonably could be anticipated.

Pinnacle West perhaps could have cancelled Redhawk during a narrow window after the first of these new projects were announced and before it signed the Redhawk EPC contract if it believed that APS could secure power from one or more of the merchant generators on at least as favorable of terms and with the same degree of assurance that the power would be available on a timely basis. But other than the three units that had been announced in 1998, none of the Arizona merchant plants actually began construction before the spring of 2001. Moreover, there was no reason to assume that the cost of a contract for the output of a new combined cycle unit owned by some other generator would be lower than the cost of a contract with PWEC for power from Redhawk; a merchant unit would not be built to serve a long-term contract at less than full cost. Moreover, under the Settlement, there was no provision for APS to enter into such a contract and, even were it to enter into it, there was no assurance that it could retain the contract rather than divest it to PWEC by the end of 2002, since the Electric Competition Rules had defined "generation" to include such contracts.

Q. Did the Western U. S. energy crisis affect Pinnacle West's options?

A. Yes. Beginning in May of 2000 prices exploded in the WECC and remained quite elevated into the summer of 2001. Forward prices also were elevated, reflecting both views of gas prices and an acknowledgement that power could well be in short supply, leading to shortage pricing, for a prolonged period. During this period, long-term contract prices moved to at least the full cost of new generating plant. An example is the contracts entered into by the California Department of Water Resources (CDWR) in the winter of 2000-1. As has been widely reported, the average cost of these contracts, totaling in excess of 10,000 MW, was $69/MWh. By no later than the second half of 2000, APS could not have signed a long term contract for power for a cost as low as the construction cost of its new units, even setting aside the fact that the units were partly built and much of their cost was "sunk."

In mid-2000, Redhawk 1 and 2 construction was accelerated to come on line by summer of 2002. This provided a reliability and energy cost backstop in case the SCE purchases could not be made. This became increasingly likely as the crisis continued and the cost to California of its load being substantially unhedged mounted. In addition, steps were initiated to bring back capacity APS's mothballed capacity, and for PWEC to install temporary capacity, to meet APS's load in 2001. West Phoenix 4 also was a critical element of the plan to meet 2001 load.

Q. You mentioned the CDWR long-term contracts. Why didn't Pinnacle West sell long-term contract power to CDWR?

A. By January and February of 2001, when the contracts were solicited, Pinnacle West was no longer long. The planned purchase of SCE capacity had gone away and the company no longer had enough planned resources to meet APS's load. The effect of the loss of the SCE purchase on its supply-demand balance was, in part, compensated by the termination of partnering arrangements with Reliant and Calpine. Nonetheless, Pinnacle West's total existing and planned resources were less than APS's requirements in each year from 2001 and thereafter.

Of course, had PWEC been a stand-alone unregulated market generator, it likely would have viewed the situation quite differently. PWEC had generation coming on line beginning in the summer of 2001 and would be hugely long when it would acquire the APS generation in late 2002. It was far better positioned than many sellers who sold to CDWR to back up a contract with real assets over most of the contract period. Notably, however, Pinnacle West's corporate management chose to override PWEC's commercial interest and declined to offer a long-term contract to CDWR. It was clear that APS would need capacity from market sellers in amounts that would increase megawatt-for-megawatt by the amount that PWEC would sell. Either APS or some affiliate would need to buy replacement power from a market that (based on forward price offers) would be far more expensive that Pinnacle West's existing or new resources.

Q. **How did Pinnacle West factor the new Arizona merchant generation into its plans?**

A. As new units were announced in late 1999 and in 2000, most of them combined cycle units, it became increasingly likely that the Western U.S. would have a surplus of energy (MWH) even if summer capacity margins (MW) remained relatively tight. Pinnacle West's planners began looking at changes in its resource plan that would make it less energy long and/or better able to take advantage of anticipated lower cost off-peak markets. In particular they began to reassess the schedule for Redhawk 3 and 4. This reflected Pinnacle West's increased willingness to be slightly short against the market in those years for which modification of its resource balance still was an option. The 2001 system plan showed that corporate resources would be short relative to APS's requirements by about 350 MW in 2003-5. This reflected an anticipation, also shown in its market price forecasts, that the market would cool in the face of new construction and resurgent reserves.

These market expectations could not, however, materially impact West Phoenix and Redhawk 1 and 2. West Phoenix remained necessary to meet load in the Valley. The first two Redhawk units were heavily committed; too much of their costs were sunk for cancellation to be cost-effective even if prices turned out to be well below forecasts made in 2000-2001. Thus, by the time prices softened in 2001 and it became more likely that at least some of the Arizona merchant plants would be built and not fully committed to California and thus would be available to serve Arizona loads, canceling either West Phoenix or Redhawk 1 or 2 was not an option. Indeed, as early as November 2000, when construction started, over $500 million had been contractually committed to Redhawk construction.

Q. You several times have mentioned Pinnacle West's continued reliance on the terms of the Settlement during this period. Should Pinnacle West and APS management have anticipated that the Settlement would be modified?

A. No. The ACC had given no indication that it would seek to unilaterally modify the terms of the Settlement. Nor did Pinnacle West and APS take any action likely to cause the ACC to do so. As I have discussed, management throughout this period was concerned with protecting APS and its customers, even at the expense of PWEC profits.

Nevertheless, in the spring of 2001, management began to consider the effect of APS buying 100 percent of its requirements from the market. This was motivated both by its concern for APS's customers and a concern for APS's financial integrity. APS, like SCE and PG&E who were fully or nearly bankrupted by having to buy the majority of their power from the market, was subject to a rate freeze. If APS were required to buy all of its needs from the market, then it would be trapped between high market prices and a fixed (indeed, declining) retail tariff, precisely as had occurred in California in 2000.

In part also, the analysis was driven by uncertainty about how regulation in Arizona might change. California had, by then, cancelled the planned sales of generation by both SCE and PG&E and, generally, was seeking to role back both retail access and dependence on competitive markets. Nevada also had put the brakes on its restructuring plans, including the sale of Nevada Power's owned generation. Several other states, primarily in the West and nearby areas in the southern mid-west, also had frozen or abandoned restructuring. While APS and its customers were largely unaffected by the western power crisis, unlike California and Nevada, and the ACC had shown a much stronger commitment to restructuring than some other states that halted steps to restructure, it was viewed as quite possible that the ACC would seek or even require arrangements that would assure that APS would be protected from what was then an out-of-control market.

As a consequence of these concerns, Pinnacle West analyzed three cases that included the required transfer of APS's generating assets to PWEC with APS relying fully on the competitive market and two versions of re-integration of APS with the Pinnacle West generating assets. One such case provided that the assets being constructed by PWEC would be transferred to APS on a book cost basis. The other assumed that the APS assets would be transferred to PWEC as agreed, but a long-term contract, essentially at cost of service, would be signed between APS and PWEC.[12] Either of these re-integration scenarios assumed that the requirement that APS buy from the market as envisioned by the Electric Competition Rules would be waived or terminated.

Using its April 2001 price forecasts, it was found that the cost of meeting APS's load would be higher under the full market reliance scenario called for in the Electric Competition Rules than under the options that retained the APS and PWEC assets for system use, either via contract or re-regulation. In particular, the expected cost of meeting APS's load in 2002 and 2003 under the terms of the Settlement was considered likely to cause severe financial difficulty to APS as a result of the rate freeze. From a Pinnacle West-wide enterprise perspective this was not a first order, direct bottom-line profit issue, since losses at APS occasioned by having to buy at market prices would be counterbalanced by high profits at PWEC

[12] A fourth case in which only the existing APS assets were retained was originally specified but determined to be so impractical and unlikely that the analysis of it was never completed.

if it also transacted at market prices. However, true exposure of APS to the expected market would have impacted its financial integrity, adversely affected its bond ratings and likely would have led to a request for emergency rate relief, as was permitted under the Settlement.

As the market cooled in late spring, near-term price forecasts declined sharply. However, the long-term forecast worsened. From an APS customer perspective, the situation actually worsened since lower prices during the rate freeze were counter-balanced by higher prices post-freeze. Reanalysis of the three cases with these later (June 2001) forecasts reaffirmed that the status quo full market reliance scenario still was higher cost to APS and its customers than either of the reintegration scenarios.

Based on these results and other considerations, Pinnacle West determined that its preferred course of action would be to propose to reintegrate via a long-term contract with PWEC. While the decision that reintegration would be its preferred option was made in the late Spring of 2001, it took considerable time for APS and PWEC to agree on the specific terms of the contract, which delayed filing of the proposed PPA and request for a variance from the competition rules with the ACC until later in the year.

What is significant about Pinnacle West's choice to reintegrate by contract in the Spring of 2001 is that, based on then-expected prices, this was <u>not</u> the most profitable course of action for Pinnacle West. The PPA would yield significantly lower revenues to PWEC than would expected market prices. Consumers would have been shielded from these market prices (and APS correspondingly exposed), but only until the rate freeze ended, which was well before the earliest termination date for the PPA. Thereafter, it was expected, based on then-forward price forecasts, that customers would pay higher prices absent the PPA. Hence from an overall corporate profitability perspective, the contract was a non-event until the rate freeze expired in 2004, but subsequently less profitable to the corporation than the "status quo" – the arrangements under the Settlement -- thereafter.

Q. What do you conclude from this review of resource studies and business decisions over the period through 2001?

A. First, from a Pinnacle West corporate point of view, the decision to build the West Phoenix and Redhawk units was prudent in terms of its responsibility for meeting APS's customers' needs. The same decision would have been prudent if a) APS had remained integrated; b) PWEC were a stand-alone merchant generator owning these assets along with the existing APS assets, or c) Pinnacle West, as the parent of both companies, was the guarantor that APS load would be met reliably and economically, as was the case in any event. Based both on my current review of the Pinnacle West planning studies and decisions, and my reviews of studies and discussion at the time, Pinnacle West's corporate strategy was dominated by its concern with protecting APS's customers and APS's financial integrity. As the PPA offer in 2001 would demonstrate, Pinnacle West was prepared to sacrifice significant enterprise profits in order to protect the customers that APS had served for nearly a century, as well as the utility itself.

V. REVIEW OF APS SYSTEM PLANNING IN 1998-2001

Q. What do you conclude as a result of your review of Pinnacle West's planning activities?

A. The resource planning analysis and related management decisions were of high quality. The resource planners engaged in numerous and frequent studies of southwestern and western power markets. They performed numerous scenario analyses and sensitivity studies. Planners used state of the art models. They also closely monitored new construction, both in Arizona and throughout the west.

As I stated in my summary, I have reviewed numerous planning studies in preparation for this testimony and, in many cases, contemporaneously. The quality, frequency and diversity of these studies are state of the art. The company's planning personnel are highly experienced, skilled and knowledgeable Databases were carefully prepared and models of the highest quality were employed. The corporate culture allowed planners to reach technical and economic judgments based on their analyses and expertise, rather than to ratify pre-determined corporate policies and strategies. I know from my own experience that at key points outside independent experts were brought in to review the analyses and resultant recommendations.

As I have just discussed, Pinnacle West's planning and decision making was "APS-centric." However, it also recognized that Pinnacle West – both its generation arm and APS – would be participating in the western power market and its planning and decision-making was informed by monitoring and analyzing the entire western market, in terms of supply and demand balances and prices.

Pinnacle West showed no bias toward construction. If anything, its preference was to rely as much as is prudent on competitive markets, taking advantage of anticipated low prices, and to buy existing resources rather than build new ones. Its recognition that partners brought complementary abilities and its desire to spread plant-specific risks was illustrated by efforts to engage in joint ventures with experienced developers and marketers.

A hallmark of Pinnacle West's resource planning decisions was their flexibility. Initially, the company focused primarily on supplemental economy market purchases. As load grew, it responded by, first, building new facilities to meet the needs of the Valley load pocket and by seeking to buy existing facilities while backstopping the risk that purchases would not materialize with a flexibly scheduled Redhawk. As it became clear that the short-term market was a dangerous place to be, and that the shares of existing resources would not be available, Pinnacle West moved up the schedule for Redhawk.

During the western energy crisis, Pinnacle West's planning deserves particularly high marks. During my long association with the planning group, they always have been focused on market fundamentals. This fundamental view led them to forecast that the worst of the immediate crisis would be of relatively short duration. Unlike other load serving entities in the West, Pinnacle West did not engage in panic buying of long-term power during the heart of the crisis. Of course, Pinnacle West could afford to be more sanguine than others, since the retention of existing generation and the ownership of the new PWEC assets meant that, at least on an energy basis, the company was unlikely to be a net buyer in the market.

VI. CONSTRUCTION PRUDENCE

Q. Turning to the prudence of the construction of the PWEC Arizona generation, as distinct from the decision to build the units, how is construction prudence addressed?

A. In some cases, this is done by a detailed audit of construction management and the costs of construction. A simpler method is to first benchmark the cost of construction. If the construction cost of a unit is within the general range of the cost of other such plants, the presumption of prudence is upheld and there is no need for the type of detailed and expensive audit that was performed for the Palo Verde nuclear plant.

Q. Have you undertaken such a benchmarking study?

A. Yes, within the limits of what is achievable. Unlike previous periods in which the cost of new units was apparent from FERC Form 1 data, cost data are not now uniformly available.

Q. What data have you used for benchmarking?

A. I have utilized two data sets. The first is the RDI NewGen database. Specifically, I culled data on all combined cycle units coming on line in 2001 through early 2003. The second source is the California Energy Commission's database on new generation in the WECC. From this database, I extracted data on all completed combined cycle units that either have come on line or are under construction with a near term planned completion without a major deferral in on-line date (i.e. without a construction stoppage).

Q. Are these databases comprehensive?

A. No. Each database contains many units for which no construction cost estimate is present. Somewhat surprisingly, there is very little overlap in the two databases. That is, most of the units for which cost data are contained in the CEC database have no cost data in the RDI database, and conversely. There is no reason to believe that the incompleteness of data biases the sample for which cost estimates are available.

Q. How confident are you of the cost data contained in these two sources?

A. The cost data likely are broadly representative, but are known to be biased downward.

Q. How do you know that the cost estimates are biased downward?

A. I know because for some of the units I have confidential cost information from other sources that shows significantly higher costs than are reported in these databases. Also, I know how these data are collected, and why it is that these sources will cause the data to be biased.

Q. Please explain the source of the bias.

A. The cost information comes from public announcements by the owners. However, costs as announced often exclude certain cost elements and often are early, design cost estimates that exclude cost growth as the project contracts are let and design is completed. Moreover, some projects overrun because they encounter construction problems or equipment failures. The types of cost that may be excluded include interest during construction and other owner's costs, transmission-related costs and spare parts. The growth of cost from initial design estimates is exemplified by Pinnacle West's units. For example, as discussed by Mr. Bhatti, West Phoenix 4 was initially forecast to cost $60 million and ultimately cost $78 million Redhawk was initially forecast to cost $250 million per unit and ultimately cost $286 million per unit. West Phoenix 5 initially was forecast as $251 million and is now forecast to cost $289 million.

Q. **How do you know that the databases include these types of original cost estimates as opposed to final costs?**

A. Both the RDI database and the CEC database include West Phoenix 4 and each shows a cost of $60 million. The CEC database includes Redhawk 1 and 2 at a cost of $250 million per unit, and West Phoenix 5 at $255 million. Also, I have an older version of the CEC database dating back to 2001. I checked it and found that the same cost data are contained in it as are contained in the current CEC database. Thus, while entries in the database indicate that data have been updated in the interim, apparently, the update does not include updated costs.

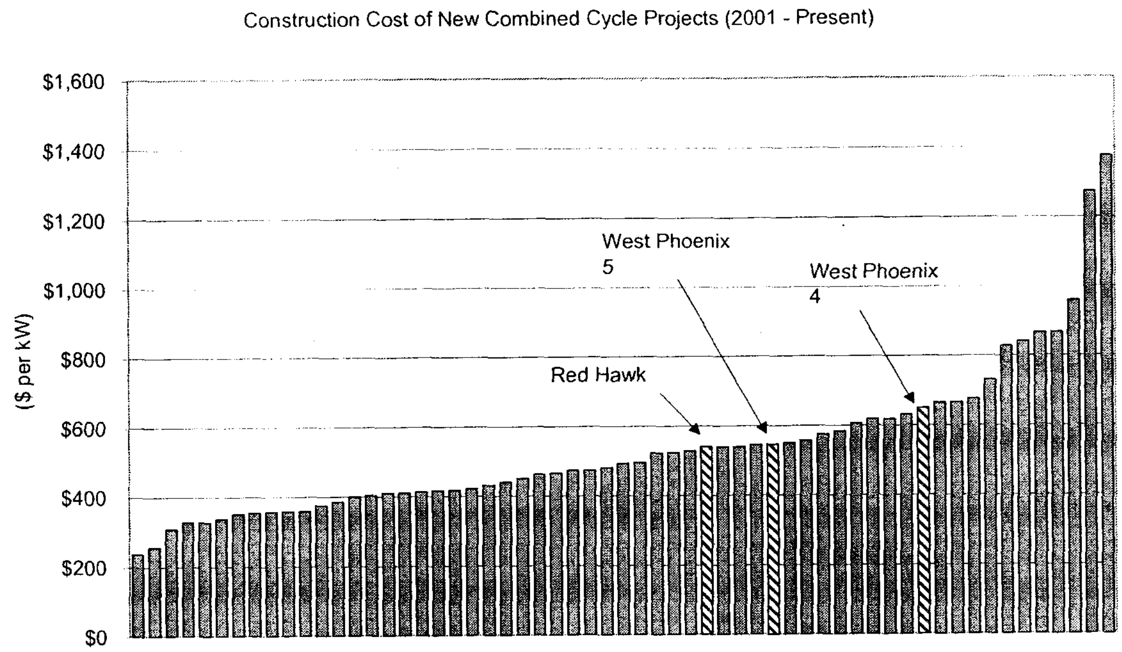
Q. **In view of these biases, why have you used these data for benchmarking the Pinnacle West units?**

A. Flawed though they are, they are the only data on which I am aware. If the Pinnacle West plant costs are within the general range of these downward biased data, then the costs of the plants clearly was reasonable.

Q. **What does the RDI database show to be the cost of new combined cycle units?**

A. The simple average cost is $535/kW with a range of $413/kW to $1375/kW. I am inclined to distrust both of the extremes. Figure WHH-1 shows the data graphically, with the Pinnacle West units included. The Pinnacle West units are well within the pack, notwithstanding the data biases I have described. I should also note that units coming on line earlier tend to have lower costs and that smaller units tend to be more expensive on a per-kW basis.

Figure 1



Q. What do the CEC data show?

A. The CEC data average $578/kW with a range of $383/kW to $954/kW. Again, I distrust the extremes, but the average again indicates that the cost of the APS units (approximately $550 per kW) was reasonable. Note also that if, as I have indicated, the data in these databases consists primarily of initial estimates, the comparison properly is to the initial estimates for the Pinnacle West combined cycle units. These total to $474/kW for the four units.

Q. Do the CEC data give any guidance on the cost of the Saguaro peaking unit?

A. The database includes cost data for a few units. They range from $417/kW to $1000/kW. At $500/kW, the Saguaro unit is toward the bottom of the range. The final cost of the Saguaro unit was slightly under the design budget and hence is lower still.

Q. What do you conclude from this benchmarking?

A. The cost of the Pinnacle West units clearly is within a reasonable range as demonstrated by this comparison. If one takes into account the biases in the databases, Pinnacle West's combined cycle units were built at a cost below the average for comparable units. Its simple cycle Saguaro units also benchmarks favorably. Hence, I conclude that these units were built at reasonable costs, from which I infer that their construction was prudently managed and executed.

VII. THE PWEC ASSETS ARE USED AND USEFUL

Q. Please define the term "used and useful" as it normally is used in electricity regulation.

A. In its origins, the term is equivalent to "used in utility service". The concept was that investments and expenses that were not related to serving customers should not be recovered in rates. For example, Pinnacle West's investment in Suncor, a real estate venture, is not recoverable in rates.

Q. How is the "used and useful" test typically conducted for electric utility generation?

A. The used and useful test has been applied to generating plants primarily in the rate cases in which the utility was seeking to ratebase a new unit. Almost invariably, the used and useful test was conducted by comparing the total megawatts of the utility's capacity with its load requirement. In some cases, a unit was used and useful if any part of it was needed to meet the strict standard of load plus reserves. In other cases, plant was subject to exclusion on a megawatt-by-megawatt basis if not needed. In still other cases, costs were disallowed only if no part of the plant would be needed within some reasonable period of time. In some cases, any disallowance was not specific to the new unit.

Q. How does the used and useful standard differ from the prudence standard?

A. As described previously, the prudence standard looks at whether decisions were reasonable at the time that they were made, considering what was known or reasonable knowable at the time. This is a "no hindsight" test that does not depend on ultimate outcomes. Conversely, used and useful looks at an ultimate outcome, whether in fact the unit was needed to meet load, given what load turned out to be when the owner sought to put it into ratebase. Because load growth is inherently uncertain, this test is less "fair" than the prudence test, unless it is applied reasonably – i.e. to allow a reasonable margin for forecast uncertainty and the lumpiness of economic plant additions.

Q. Is there a potential inconsistency between the prudence standard and used and useful and, if so, how should that inconsistency be resolved?

A. Yes, there is a potential inconsistency. The prudence standard is inherently forward looking from the perspective of what was known or knowable when decisions were made. In most instances, prudence would subsume the issue of whether the plant reasonably was believed to be used and useful, once completed, at that time. The used and useful test, as generally practiced, compares resources to needs as anticipated at the time of the ratecase, *i.e.,* with the benefit of hindsight concerning actual rather than unanticipated load growth. In extreme cases, even a "fair" used and useful test could be failed, in whole or in part, with respect to a prudently planned and constructed plant.

For this reason, the proper course is to give primacy to the prudence standard. Fortunately, in this case the issue of which standard should dominate need not be faced since the investment is both prudent and used and useful.

Q. **Are the PWEC assets that APS is seeking to ratebase used and useful?**

A. Yes. West Phoenix 4 has been used and useful beginning in the summer of 2001. Saguaro and Redhawk have been used and useful since the summer of 2002. West Phoenix 5 will be used and useful when it comes into service this summer. When I state that they are used and useful, I mean that they are needed to meet reliability and that they also are used to meet native load.

While it is the case that these assets already are used and useful, the actual application of the test, in Arizona and elsewhere, is related to the period beginning when rates go into effect. When the rates set in this case go into effect, most likely no earlier than sometime in the latter half of 2004, APS's load during the peak season will be met in substantial part by these assets that are under contract to serve that load. Notwithstanding this contract, and other contracts signed during Track B, APS is projected to be short of capacity by 2004 and increasingly short in every year thereafter. Moreover, the bulk of the capacity that APS has under contract as a result of Track B is the PWEC Arizona capacity.

VIII. LESSONS FROM THE TRACK B PROCUREMENT

Q. What can be learned from the Track B procurement?

A. First, with the exception of PWEC, suppliers generally were unwilling to enter into contracts at below the expected spot prices for the contract period. A few offers were slightly in the money, based on APS's forward price curves. These slight discounts likely reflect that some sellers had a slightly lower forward price curve than did APS, rather than a willingness to sell below the forward market. This result should come as no surprise: a profit maximizing seller will not deliberately sell via contract for less than it can get in other sales venues.

Second, a substantial part of the non-PWEC Arizona merchant generation was not offered at all. In addition to the 150 MW from Sundance that APS accepted, only 1512 MW were offered.[13] In addition, approximately 630 MW was offered by power marketers, at least some of which may have been backed by Arizona generation. Nothing was offered by several large generation owners such as Duke and Sempra, nor from load serving entities, such as SRP, WAPA or AEPCO. In addition, not all of this bid power was deliverable because the bidders selected transmission paths that could not simultaneously accommodate all of the bid amounts. APS estimates that the total amount of non-PWEC generation that could have been delivered if PWEC used none of the constrained interfaces would have been 1,463 MW in 2004 and lesser amounts in other years. Had PWEC not bid, and made the offers that it did, APS would have received very little power

[13] Cited totals are for 2004, the peak year of offers.

priced at or below its forward price curve. It would have been able to contract for only a fraction of its needs, about half, at <u>any</u> price.

Third, there was very little non-PWEC capacity offered on a long-term basis. APS was offered 225 MW of peaking capacity and 300 MW of combined cycle capacity (from a unit that has not begun construction or even received a Certificate of Environmental Compatibility) beginning in 2006. Both of these offers were out of the money. It also received a very small intermediate term (five-year) non-asset-backed offer from a power marketer.

The absence of long-term offers suggests that potential sellers view the post-2005 market with greater optimism than is reflected in current forward markets. To the extent that their capacity is not already committed to other buyers, sellers apparently prefer to accept the risks of selling short term for the next year or two in order to preserve the value of having capacity to sell at market in later periods.

The paucity of offers at a time when prices in the market are so depressed that sellers are going bankrupt speaks volumes about the folly of requiring that APS commit to replace the contracts and buy needed new supply to meet load growth from the market when its current Track B contracts expire at the end of 2006. As discussed below, the current glut of capacity likely will have fully disappeared by about that time. At best, APS would have to compete head-to-head against California for the Arizona merchant capacity. The ACC cannot reasonably expect that PWEC, having twice been denied a long-term sale of its output (by contract or outright) would continue to withhold its capacity from the export contract market.

Nor can it rely on other generators having held back thousands of megawatts of capacity on the mere hope that APS will be compelled to pay higher prices than in nearby markets.

Q. What do you conclude based on your review of the Track B solicitation?

A. Even at the peak of the glut in Western power markets, there was not nearly enough non-PWEC capacity offered to meet APS's needs. APS will be significantly shorter by the time that the Track B contracts expire. There is no evidence that additional capacity will be built in Arizona. In particular, there is no evidence that in-Valley capacity will be built. The Western power market, overall, is virtually certain to be much tighter and market prices to be higher. A new solicitation held in 2006 would be unlikely to yield the capacity that APS will need at prices as attractive as the ratebase cost of the PWEC units and might not yield the needed capacity at all.

IX. OBSERVATIONS ON FUTURE WHOLESALE MARKET PRICES

Q. Can you determine at this time whether the PWEC Arizona assets are cost-effective relative to the wholesale market?

A. Let me preface my answer by noting that this question should not be relevant to ratebasing these assets since, in view of the facts, the prudent investment test is the relevant standard. This having been said, whether the assets are cost effective relative to the market can be truly determined only with hindsight 30 years from now. A forecast of whether they are likely to be cost effective depends entirely on the market price forecast used. Near-term prices are forecast to be relatively low, reflecting the glut of capacity coming on line in the western U.S. in 2002-3 and the recessionary economy. Of course, these near-term forecasts are not relevant, since the rate freeze remains in effect through most or all of 2004. The only prices that matter are post-freeze prices. Market data on forward prices for the relevant period beginning in late 2004 or 2005 and extending for the life of the assets are not available or are of dubious quality. Forward markets beyond the next few quarters are illiquid and reflect small trading volumes. It simply is not possible to determine from forward market data what price the competitive market would pay for 1,700 MW of capacity in Arizona for the next 30 years or so. Even if forward markets were more liquid and robust, there is no assurance that current forecasts of market prices will prove more accurate than the sometimes wildly inaccurate forecasts of the past.[14]

Q. **Do long-term contract prices provide any guidance on the competitive value of the output of the PWEC assets?**

A. No. Long-term contract prices generally are unobservable. The last group of long term contracts for which price terms were disclosed publicly was the CDWR contracts signed between February and August of 2001.

Q. **Do you have an opinion, qualitatively, of how long-term prices could be estimated?**

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[14] As traders always point out, a forward price curve is not the same thing as a price forecast. Forward bid-offer prices are the prices at which forward products will transact today. Any market participant may have a quite different price forecast. For example, in 2001, Pinnacle West's price forecasts were below the market curves of the time, although they still showed that a cost-based PPA brought considerable value to APS's customers.

A. Yes. In the short run, prices need to be high enough to do two things: first to pay the variable cost of the marginal producer – the highest cost unit needed to meet load at particular points in time (e.g. hourly). Second, prices need to yield enough margin to keep sufficient plant available to meet load reliably. In general, this is an additional amount that must cover, at a minimum, the "going forward" cost of plant. This includes (in addition to fuel) operation and maintenance expense (including capitalized future expenditures) associated general and administrative expense and property taxes. It needn't cover the entire sunk cost of capital investment. The shorthand for this is "short run marginal cost". The explanation I have given varies slightly from the economist's standard definition of the short run marginal cost of energy in order to reflect the need for system operating reserves, a factor that is unique to electricity.

In the long run, the expected (approximately, the average) level of prices needs to be high enough that needed new entry will be attracted. Historically, this was achieved in a different manner, by rolling new plant into ratebase. This might lower, but more typically raised, the average prices seen by ratepayers in the first years of plant operation. In a competitive wholesale market (i.e. absent cost-based regulation), the constraint that prices must be high enough to attract needed entry determines a market price that is earned by all competitive market participants. The short hand term for such prices is "long run marginal cost" or LRMC.

Q. If you know, does your description match how Pinnacle West forecasts prices?

A. Yes. I have worked with APS's planners for a number of years and can confirm that this is how they typically have forecasted prices. That is, they use short run marginal cost in the near term and LRMC for years past when markets come into balance. I note that I am talking about the planners who do long term analyses, not about traders whose focus is short term and whose methodology is different.

Q. **Do you agree that this is an appropriate way to forecast prices?**

A. Generally yes, particularly for studies of generation options that will have long lives. However, this type of "fundamental" price forecasting is not very good at forecasting price volatility or even the year-to-year trajectory of prices. It used to be a common practice to use short run marginal cost to forecast prices in the near term, then to trend prices up to long run marginal cost gradually as the need for new capacity approached. However, this ignores the "boom-bust nature of commodity markets, including electricity. In reality, new capacity will not generally be built on a "just in time" basis, thus capping prices at long run marginal costs, then holding steady at long run marginal cost for the remainder of time. Rather, it reasonably can be anticipated that the elimination of surpluses will result in quite high shortage prices until supply fully responds. This is a major lesson learned from the Western power crisis of 2000-1 as well as from other commodity markets.

Forecasts made today that ignore the "boom" portion of the cycle generally will have a downward bias, taken as a whole; that is, they will unsystematically under-forecast future prices. Since they typically will have a near term "bust" component with no off-setting "boom", they would also, on average, forecast revenues to new entrants that are below full costs. If potential entrants acted on such forecasts, entry would not occur. If the prices were to occur in fact, such entry as occurred would not be profitable

This systematic bias is relevant to any evaluation of the proposed ratebasing of the PWEC Arizona units. This bias is compounded by, and indeed arises principally from, the sensitivity of such an analysis to the timing of future price changes.

Q. **Why does the timing of price changes matter to the cost-effectiveness of ratebasing the PWEC Arizona assets?**

A. As was demonstrated by the non-PWEC bids in Track B, as well as by Pinnacle West's traders forward price curves used in evaluating the bids, the near-term market is in a "bust" cycle. That is, these prices are below the level needed to support new entry.

However, we can know with reasonable certainty that ratebasing the PWEC assets will be a good deal for ratepayers, relative to buying from a market that is in "long run equilibrium," that is, with prices equal to long run marginal costs. This is because the PWEC assets came on line in 2001-3 and were built with less inflated dollars that will be the case for the future new plants, the cost of which will determine long run marginal cost and thus set long run marginal cost-based prices. Moreover, the PWEC assets are partly depreciated. These two factors will create a continuous wedge of benefits from ratebasing these assets relative to buying at long run marginal costs.

This can be shown with a simple numerical example. Suppose that APS's best alternative to ratebasing these assets is to sign a new long-term contract with new generation to begin when the PWEC contract expires in 2006. The PWEC assets will be roughly four years old. If inflation over the 2002-6 period averages, say 2.5 percent, and depreciation is 3 percent per year, the capital cost of the new facility will be around 22 percent higher. It will remain that much higher for the life of the PWEC assets.[15]

Q. Does this discussion mean that you could derive a forward price curve to compare against the PWEC assets by using short run marginal cost or forward price curves in the near term and long run marginal cost once the current supply glut is exhausted?

A. No. This misses the factor that makes such forecasts biased downward. Electricity has been shown to be like other commodities in that it is subject to "boom-bust" cycles. The current over-supply is the "bust" from a generator's perspective. To simply move smoothly from the "bust" to long run equilibrium misses the "boom" part of the equation and would systematically undervalue the PWEC assets

Q. Can you give a quantitative example of what the "boom" prices look like?

A. Yes. In concept, the "boom" prices have to be enough higher than long run marginal cost to offset the extent to which "bust" prices are below it. It is the nature of commodity cycles involving capital intensive facilities that "booms" are shorter than "busts". That is, when prices are high, so much new capacity is built that the over-supply can last several years.

What has happened in Western power markets over the past five years provides a very telling example. Beginning with the establishment of the California PX and ISO in April 1998[16], prices were very low for two years. This was followed

[15] This example calculation ignores tax-timing effects and will somewhat overstate the difference.
[16] Prices were low before April of 1998, but the market data that I am addressing date only from the beginning of the PX and ISO markets.

by the very high prices during the 13-month crisis period and prices tailing off for another couple of months. Thereafter, prices returned to the low levels of 1998-9.[17]

As part of my testimony in the California refund litigation, I examined the contribution margin[18] for a hypothetical new combined cycle unit and a hypothetical new combustion turbine unit coming on line in April 1998. In that analysis, I assumed that the plants' output was sold in the PX day-ahead market until the PX ceased to function, and then in the ISO balancing market. Both types of units were deeply loss making, earning less than half of what was needed to cover fixed costs in the pre- and post-crisis periods. It turned out that the full amount of the very high margins earned during the crisis period was necessary to get the units back to income levels sufficient to support entry.

Specifically, I testified that in the first year, the contribution margin for a new combined cycle unit would have been \$55/kW and in the second year would have been \$65/kW. In the year beginning April 2000, the margin would have been \$377/kW and in the year beginning April 2001 (catching the last part of the crisis period) would have been \$83/kW. In the year beginning April 2002, the contribution margin would have been \$42/kW. This averages \$125/kW-year, approximately the long run marginal cost of such a unit. The peaking unit fared even worse.

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[17] While I have couched this in terms of prices, this is not strictly accurate. What matters is not prices as such but the margins over fuel costs that pay for fixed cost and a return on investment. Over this period, there was a great deal of variability in gas prices, which also affected prices. The pattern that I described is the pattern of margins, though the pattern of prices is similar.

[18] The contribution margin is the "profit" earned in excess of out-of-pocket variable costs that can be used to offset semi-fixed costs (e.g. operations and maintenance) and to provide a return on and of investment.

While this was an eye-opening result, on reflection, it was not surprising. If a unit is earning less than half of the required margin during a four-year "bust" period, it must earn more than three times long run marginal cost margin during the "boom" year. Stated slightly differently, the "boom" period margin needs to be at least 6 times the margin during the "bust" period if the unit is to cover long run marginal cost over the whole cycle.[19]

Q. Does the California experience teach any other lessons about "boom-bust" cycles?

A. Yes. There was general unanimity among all of the witnesses that the root cause of the high prices was a shortage of generation. There was less unanimity about the role of other factors (e.g. market design, market manipulation); however, even those experts who laid much of the blame on the exercise of market power testified that the ability to exercise market power and substantially affect prices was a result of the underlying shortage of power. Published analysis entered into the record in that case[20] showed a systematic relationship between tight reserve margins and the ability of generators to raise prices substantially above the short-term marginal cost of energy. Hence, the next substantial price spike (setting aside the effects of gas prices) should coincide with the working off of the current capacity surplus.

[19] This assumes that it earns half of the required contribution margin in glut years, a better performance than seen in the western power markets over the past five years. Under this assumption, it must cover its full cost in the boom year, plus make up the half that was not covered during the other four years. Six halves is six times the glut margin.

[20] Borenstein *et al.*, "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market," 92 American Economic Review (Dec, 2002). Cited in Exhibit No. CSA-2, Prepared Testimony of Steven E Stoft, Ph.D on Behalf of the California Electricity Oversight Board and the California Public Utilities Commission, Exhibit No. CSA-2 in FERC Docket No. EL00-95-075 *et al.*

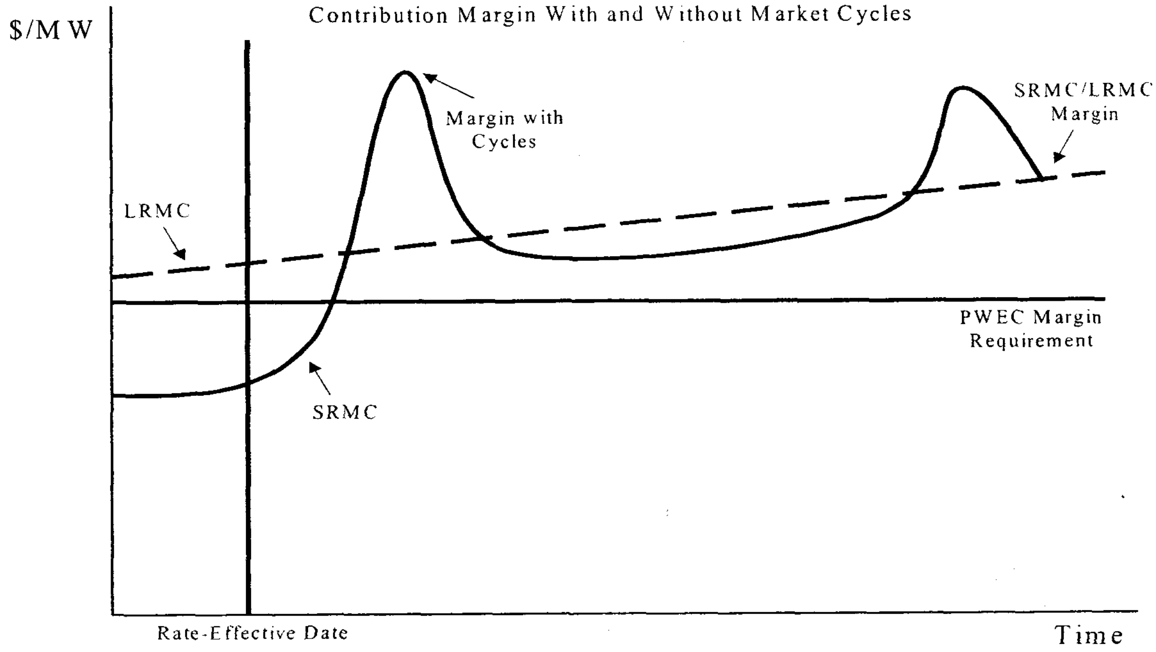
Q. **Can you provide a numeric example of why it is important to take into account the timing of the next "boom" period in any going-forward evaluation of rate basing the PWEC assets?**

A. Yes. Figure WHH-2 contrasts between the two methods of forecasting that I have just described. Common to both examples are four assumptions. First, new capacity is needed in 2007, an assumption that I believe to be valid for reasons I will discuss later. Second, the cycle is eight years long. I believe that this assumption is ballpark correct, but it is of no significance to the analysis; any reasonable assumption would yield similar results. Third, I assume that over the course of each such cycle, the net present value of prices is equal to long run marginal costs. Fourth, I reflect the fact that the book cost of the PWEC assets is below the cost of an otherwise identical unit (the marginal cost-determining unit) coming on line in 2007.

"Prices" used are annual per-kW contributions to fixed cost and financing costs, not KWh prices. That is, the time weighted average price over a cycle is sufficient to cover the annualized cost (return on and of, plus fixed O&M) of a new combined cycle unit. The contribution margin permits the analysis to abstract from variable costs, principally fuel. Near-term prices in the buy-from-market case are assumed to be below LRMC through 2006. In the purchase case, they are set by the ratebase cost of the units.

In both cases, long run marginal cost is the same. The sole difference between the cases is whether the "boom-bust" nature of the market is taken into account or not.

Figure 2
Contribution Margin With and Without Market Cycles



Because the PWEC Arizona assets enter into ratebase relatively near to the beginning of a boom, the value of the assets is greater in the boom-bust model. The fact that it is much more cost-effective for ratepayers if APS acquires the assets at book value near the beginning of a "boom" hardly is surprising. The acquirer avoids the cost of ownership for much of the "bust" period and attendant low prices for off-system sales, and is primed and ready to avoid high market prices during the "boom" period. Of course, this result arises solely from the fact that the assets are acquired at book value. The market value of assets will rise as the anticipated boom period gets closer. Thus, for example, assets purchased in California that provided energy during the "boom" actually were worth substantially more than their value under long run marginal cost conditions.

Q. **Does your example include the value of the asset purchase in terms of enhanced reliability during periods when the market is tight?**

A. No. The example assumes that APS will be able to buy all of the power that it needs from the market. In reality, we know from the Western power markets crisis of 2000-2001 that while utilities such as the Arizona utilities and LADWP that controlled the resources that they needed avoided rolling blackouts and power emergencies, the power-short IOUs in California did not.

Q. **You have emphasized the importance of acquiring capacity close to a boom period. Have there been studies that suggest how long it will take before a shortage of capacity reemerges in the western U. S., setting off another round of scarcity prices?**

A. Yes. A recent California Energy Commission study[21] concluded that reserves available to California should be adequate for the next two years, but that continued adequacy required additional conservation measures and/or new capacity. A review of the CEC's calculations actually is a bit more alarming. First of all, it assumes merely average temperature conditions. One-year-in-ten temperatures increase requirements by between 6.5 and 7 percentage points. Second, while only plant scheduled to be competed in 2003 or at the latest early 2004 can be regarded as committed to be built, the CEC assumes an additional nearly 4,000 MW of

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[21] "California 2003 Electricity Supply and Demand Balance and Five-Year Outlook", available at http://www.energy .ca.gov/electricity/2003_SUPPLY_DEMAND_PEAK.pdf

capacity is built in California in the few years after that period, primarily to come on line by the summer of 2005. Without that capacity, California has inadequate operating reserves by 2006-7 under normal weather conditions and by 2005 in one-year-in-ten temperature conditions. Third, the study assumes that California can count on nearly 8,500 MW of on-peak imports in each year. The bulk of these are stated to be under contract. However, the study assumes that 2,700 MW of imports are available in each year beyond the amounts contracted.

Building 4,000 MW of new capacity in California, primarily in 2005, is not consistent with prices that remain below long run marginal costs. The assumed level of availability of imports also is highly questionable. Contracted imports already include a substantial (albeit unknown) amount of Desert Southwest merchant capacity.[22] As Mr. Bhatti testifies, Arizona load growth likely will absorb all of the available surplus of merchant capacity in Arizona within two to three years. APS, in particular, is forecast to be 1,100 MW short, even taking into account all of the PWEC Arizona capacity. From where, then, will California get the additional 2,700 MW of imports? It is precisely this kind of blind faith reliance on non-California generation that was the root cause of the power crisis of 2000-1 that dragged down the entire West.

While load forecasting is highly uncertain, and forecasting reserve levels still more so, the foregoing suggests that (unless actions not currently apparent are

[22] Nearly all of the imports (other than capacity owned by LADWP and SCE) likely relates to the contracts signed with CDWR. One of those contracts is with Sempra. In view of the fact that it did not bid into the Track B auction, it is likely that Sempra is using Mesquite to fulfill part of its contract. Other contracts are with power merchants who are relying on contracts with unknown generators. At least some of these

taken) the Western U.S. will again be in a reserve deficit situation by around 2006 or 2007. Indeed, under one-in-10 weather, unless the phantom new capacity is built and the rest of the WECC remains in substantial surplus, California will be deficit in operating reserves to about the same degree as in 2000-1 by the 2006-2007 timeframe. Even this grim result assumes low-normal hydro, not the highly adverse conditions experienced in 2000-1 and assumes no "gaming" of the market that involves the withholding of capacity.

As happened in 2000-1, when California catches cold, the rest of the West catches pneumonia. As California bids away the remaining uncommitted capacity from the Desert Southwest, price arbitrage between the markets will cause prices to rise to more-or-less equivalent amounts. Of course, to the extent that APS's ratepayers are protected by owning assets or by long term purchased power agreements, such a crisis will not affect them adversely and may even benefit them to the extent that APS has excess energy to sell into the market.

Q. **Is this view of the market consistent with the actions of non-PWEC bidders in the Track B auction?**

A. Yes. As discussed earlier, with minor exceptions, bidders did not offer to sell into the auction beyond 2005.

Q. **If sellers anticipate a "boom" spike in prices in the middle of the decade, how would this affect their offers for contracts to replace or supplement the contracts that are due to expire at the end of 2006?**

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contracts are with Desert Southwest generators. As Mr. Bhatti testifies, Pinnacle West believes that approximately 3,000 MW of Arizona merchant capacity has been sold out of state.

A. They would price this into their contract offers. Contract offer prices are the risk-adjusted equivalent of expected future short-term prices. This is both common sense and demonstrated by the long term contracts signed during the last power crisis.

Q. Would this calculus apply to PWEC as well as to other bidders?

A. Yes. PWEC would face the same opportunities in export markets as would other generators and power marketers. A profit maximizing PWEC would not sell to APS for less than it could receive elsewhere, particularly having twice offered its capacity to APS's customers at cost-of-service prices and been turned down. Further, unless someone else builds new capacity within the Valley load pocket, PWEC would face no effective competition to meet the reliability must run requirement. Doubtless, FERC market power mitigation would place some limits on what it could charge. However, under current policies, the permitted price would certainly be no less than the cost of ratebasing the West Phoenix plant.

X. CONCLUSIONS

Q. Please summarize your conclusions.

A. My conclusions can be summarized briefly as follows. First, the PWEC Arizona units were prudently planned to meet APS's load. Second, they are used and useful in meeting that load. Third, they were constructed at reasonable costs, consistent with the cost of similar units built by other companies. Fourth, the Track B responses signal that the market is likely to tighten at about the time that existing contracts end. Fifth, this likely tightening makes it quite risky in terms of reliability, prices and price volatility, to rely on the market for the capacity that ratebasing these assets would cover. Sixth, ratebasing the PWEC assets likely will be economic relative to the market for the capacity and energy that they provide.

Q. Does this complete your prefiled direct testimony in this proceeding?

A. Yes, it does.

Appendix A

WILLIAM H. HIERONYMUS — Vice President

Ph.D.	Economics, University of Michigan
M.A.	Economics, University of Michigan
B.A.	Social Science, University of Iowa

William Hieronymus has consulted extensively to managements of electricity and gas companies, their counsel, regulators, and policymakers. His principal areas of concentration are the structure and regulation of network utilities and associated management, policy, and regulatory issues. Dr. Hieronymus has spent the last fourteen years working on the restructuring and privatization of utility systems in the U.S. and internationally. In this context he has assisted the managements of energy companies on corporate and regulatory strategy, particularly relating to asset acquisition and divestiture. He has testified extensively on regulatory policy issues and on market power issues related to mergers and acquisitions. In his twenty-five years of consulting to this sector, he also has performed a number of more specific functional tasks, including analyzing potential investments; assisting in negotiation of power contracts, tariff formation, demand forecasting, and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of energy sector clients before regulatory bodies, federal courts, and legislative bodies in the United States and United Kingdom. He has contributed to numerous projects, including the following:

ELECTRICITY SECTOR STRUCTURE, REGULATION, AND RELATED MANAGEMENT AND PLANNING ISSUES

U.S. Market Restructuring Assignments

- Dr. Hieronymus serves as an advisor to the senior executives of electric utilities on restructuring and related regulatory issues, and he has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. Related to some of these assignments, he has testified before state agencies on regulatory policies and on contract and asset valuation.

- For utilities seeking merger approval, Dr. Hieronymus has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The mergers on which Dr. Hieronymus has testified include both electricity mergers and combination mergers involving electricity and gas companies. Among the major mergers on which he has testified are Sempra (Enova and Pacific Enterprises), Xcel (New Century Energy and Northern States Power), Exelon (Commonwealth Edison and Philadelphia Electric), AEP (American Electric Power and Central and Southwest), Dynegy-Illinois Power, Con Edison-Orange and Rockland, Dominion-Consolidated Natural Gas, NiSource-Columbia Energy, E-on-PowerGen/LG&E and NYSEG-RG&E. He also submitted testimony in mergers that were terminated for unrelated reasons, including Entergy-Florida Power and Light, Northern States Power and Wisconsin Energy, KCP&L and Utilicorp and Consolidated Edison-Northeast Utilities. Testimony on similar topics has been filed for a number of smaller utility mergers and for asset acquisitions. Dr Hieronymus has also assisted numerous clients in the pre-merger screening of potential acquisitions and merger partners.

- For utilities seeking to establish or extend market rate authority, Dr. Hieronymus has provided numerous analyses concerning market power in support of submissions under Sections 205 of the Federal Power Act.
- For utilities and power pools engaged in restructuring activities, he has assisted in examining various facets of proposed reforms. Such analysis has included features of the proposals affecting market efficiency and those that have potential consequences for market power. Where relevant, the analysis also has examined the effects of alternative reforms on the client's financial performance and achievement of other objectives.
- For generators and marketers, Dr. Hieronymus has testified extensively in the regulatory proceedings concerning the electricity crisis in the WECC that occurred during May 2000 and May 2001. His testimony concerned, *inter alia*, the economics of long term contracts entered into during that period the behavior of market participants during the crisis period and the nexus between purportedly dysfunctional spot markets and forward contracts.
- For the New England Power Pool (NEPOOL), Dr. Hieronymus examined the issue of market power in connection with NEPOOL's movement to market-based pricing for energy, capacity, and ancillary services. He also assisted the New England utilities in preparing their market power mitigation proposal. The main results of his analysis were incorporated in NEPOOL's market power filing before FERC and in ISO-New England's market power mitigation rules.
- For a coalition of independent generators, he provided affidavits advising FERC on changes to the rules under which the northeastern U.S. power pools operate.
- As part of a large planning and analysis team, Dr. Hieronymus assisted a Midwest utility in developing an innovative proposal for electricity industry restructuring.
- Dr. Hieronymus has contributed substantially to projects dealing with the restructuring of the California electricity industry. In this context he also is a witness in California and FERC proceedings on the subject of market power and mitigation and more recently before FERC in connection with transactions related to PG&E's bankruptcy and on the contracts signed between merchant generators and various buyers.

Valuation of Utility Assets in North America

- Dr. Hieronymus has testified in state securitization and stranded cost quantification proceedings, primarily in forecasting the level of market prices that should be used in assessing the future revenues and the operating contribution earned by the owner of utility assets in energy and capacity markets. The market price analyses are tailored to the specific features of the market in which a utility will operate and reflect transmission-constrained trading over a wide geographic area. He also has testified in rebuttal to other parties' testimony concerning stranded costs, and has assisted companies in internal stranded cost and asset valuation studies.

- He was the primary valuation witness on behalf of a western utility in an arbitration proceeding concerning the value of a combined cycle plant coming off lease that the utility wished to purchase.

- He assisted a bidder in determining the commercial terms of plant purchase offers as well as assisting clients in assessing the regulatory feasibility of potential acquisitions and mergers.

Other U.S. Utility Engagements

- Dr. Hieronymus has contributed to the development of several benchmarking analyses for U.S. utilities. These have been used in work with clients to develop regulatory proposals, set cost reduction targets, restructure internal operations, and assess merger savings.

- Dr. Hieronymus was a co-developer of a market simulation package tailored to region-specific applications. He and other senior personnel have conducted numerous multi-day training sessions using the package to help utility clients in educating management regarding the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.

- He has made numerous presentations to U.S. utility managements regarding overseas electricity systems.

- For an East Coast electricity holding company, Dr. Hieronymus prepared and testified to an analysis of the logic and implementation issues concerning utility-sponsored conservation and demand-management programs as alternatives to new plant construction.

- In connection with nuclear generating plants nearing completion, he has testified in Pennsylvania, Louisiana, Arizona, Illinois, Missouri, New York, Texas, Arkansas, New Mexico, and before the Federal Energy Regulatory Commission regarding plant-in-service rate cases on the issues of equitable and economically efficient treatment of plant costs for tariff-setting purposes, regulatory treatment of new plants in other jurisdictions, the prudence of past system planning decisions and assumptions, performance incentives, and the life-cycle costs and benefits of the units. In these and other utility regulatory proceedings, Dr. Hieronymus and his colleagues have provided extensive support to counsel, including preparation of interrogatories, cross-examination support, and assistance in writing briefs.

- On behalf of utilities in the states of Michigan, Massachusetts, New York, Maine, Indiana, Pennsylvania, New Hampshire, and Illinois, he has submitted testimony in regulatory proceedings on the economics of completing nuclear generating plants that were then under construction. His testimony has covered the likely cost of plant completion; forecasts of operating performance; and extensive analyses of the impacts of completion, deferral, and cancellation upon ratepayers and shareholders. For the senior managements and boards of utilitues engaged in nuclear plant construction, Dr. Hieronymus has performed a number of highly confidential assignments to support strategic decisions concerning the continuance of construction.

- For an eastern Pennsylvania utility that suffered a nuclear plant shutdown due to NRC sanctions relating to plant management, he filed testimony regarding the extent to which replacement power cost exceeded the costs that would have occurred but for the shutdown.

- For a major Midwestern utility, Dr. Hieronymus headed a team that assisted senior management in devising its strategic plans, including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition, and available diversification opportunities.

- On behalf of two West Coast utilities, Dr. Hieronymus testified in a needs certification hearing for a major coal-fired generation complex concerning the economics of the facility relative to competing sources of power, particularly unconventional sources and demand reductions.

- For a large western combination utility, he participated in a major 18-month effort to provide the client with an integrated planning and rate case management system.

- For two Midwestern utilities, Dr. Hieronymus prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee.

U.K. Assignments

- Following promulgation of the white paper that established the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional distribution and retail supply companies focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts, and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.

- During the preparation for privatization, Dr. Hieronymus assisted several individual U.K. electricity companies in understanding the evolving system, in developing use of system tariffs, and in enhancing commercial capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers, and financial institutions on the U.K. power system for a number of years after privatization.

- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for a 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.

- Dr. Hieronymus also has consulted on the separate reorganization and privatization of the Scottish electricity sector. Part of his role in that privatization included advising the larger of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation, and company strategy.

- He assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment was consideration of such policy issues as incentives for the economic purchasing of power, the scope of price control, and the use of comparisons among companies as a basis for price regulation. Dr. Hieronymus's model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.

- He assisted one of the Regional Electricity Companies in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

Assignments Outside the U.S. and U.K.

- Dr. Hieronymus assisted a large state-owned European electricity company in evaluating the impacts of the 1997 EU directive on electricity that *inter alia* requires retail access and competitive markets for generation. The assignment included advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.

- For the European Bank for Reconstruction and Development, he performed analyses of least-cost power options and evaluated the return on a major investment that the Bank was considering for a partially completed nuclear plant in Slovakia. Part of this assignment involved developing a forecast of electricity prices, both in Eastern Europe and for potential exports to the West.

- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.

- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, Dr. Hieronymus developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command-and-control system to a decentralized, corporatized system.

- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation, and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.

- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which was to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization is based on regional electric power companies, linked by a unified central market, with market-based prices for electricity.

- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, Dr. Hieronymus continued to advise both the Russian energy and power ministry and the government-owned generation and transmission company on restructuring and market development issues.

- On behalf of a large continental electricity company, Dr. Hieronymus analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and to assist the client in understanding their implications.

- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.

- For a task force representing the Treasury, electricity generating, and electricity distribution industries in New Zealand, Dr. Hieronymus undertook an analysis of industry structure and regulatory alternatives for achieving the economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition, and regulatory requirements.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

- Dr. Hieronymus participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies for transmission, including incentives for efficient investment and location decisions.
- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes.
- For EPRI, Dr. Hieronymus directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.
- For the EPRI-NARUC Rate Design Study, he developed a methodology for designing optimum cost-tracking block rate structures.
- On behalf of a group of cogenerators, Dr. Hieronymus filed testimony before the Energy Select Committee of the UK Parliament on the effects of prices on cogeneration development.
- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines regarding fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guidelines on cost-of-service standards.
- For private utility clients, Dr. Hieronymus assisted in the preparation both of their comments on draft FERC regulations and of their compliance plans for PURPA Section 133.
- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.
- For DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.
- For the commissioners of a public utility commission, Dr. Hieronymus assisted in preparation of briefing papers, lines of questioning, and proposed findings of fact in a generic rate design proceeding.

SALES FORECASTING METHODOLOGIES FOR GAS AND ELECTRIC UTILITIES

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force, and it formed a basis for the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.
- For a large eastern utility, Dr. Hieronymus developed a load forecasting model designed to interface with the utility's revenue forecasting system-planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.
- For DOE, he directed development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and provided a forecasting model for their interim use.
- For state regulatory commissions, Dr. Hieronymus has consulted in the development of service area-level forecasting models of electric utility companies.
- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.
- For a Midwestern electric utility, he provided consulting assistance in improving the client's load forecast, and testified in defense of the revised forecasting models.
- For an East Coast gas utility, Dr. Hieronymus testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These cases have included Sherman Act Section 1 and 2 allegations, contract negotiations, generic rate hearings, ITC hearings, and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor, Dr. Hieronymus testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, Dr. Hieronymus assists clients in Hart-Scott-Rodino investigations by the Antitrust Division of the U.S. Department of Justice and the

Federal Trade Commission. In an arbitration case, he testified as to changed circumstances affecting the equitable nature of a contract. In a municipalization case, he testified concerning the reasonable expectation period for the supplier of power and transmission services to a municipality. In two Surface Transportation Board proceedings, he testified on the sufficiency of product market competition to inhibit the exercise of market power by railroads transporting coal to power plants.

- For a landholder, Dr. Hieronymus examined the feasibility and value of an energy conversion project that sought a long-term lease. The analysis was used in preparing contract negotiation strategies.
- For an industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, Dr. Hieronymus developed an estimate of the potential market for the system by geographic area.
- For the U.S. Environmental Protection Agency (EPA), he was the principal investigator in a series of studies that forecasted future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has been an invited speaker at numerous conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervener strategies in utility regulatory proceedings, utility deregulation, and utility-related opportunities for investment bankers.

Prior to rejoining CRA in June 2001, Dr. Hieronymus was a Member of the Management Group at PA Consulting, which acquired Hagler Bailly, Inc. in October 2000. He was a Senior Vice President of Hagler Bailly. In 1998, Hagler Bailly acquired Dr. Hieronymus's former employer, Putnam, Hayes & Bartlett, Inc. He was a Managing Director at PHB. He joined PHB in 1978. From 1973 to 1978 he was a Senior Research Associate at CRA. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving as a Captain in the U.S. Army

APS-9

EXHIBIT

APS - 9

admitted

TESTIMONY OF JOHN H. LANDON

ON BEHALF OF

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-____

MANAGING PRINCIPAL AND DIRECTOR,

ENERGY AND TELECOMMUNICATIONS PRACTICE,

ANALYSIS GROUP, INC.

June 27, 2003

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DIRECT TESTIMONY OF JOHN H. LANDON

(DOCKET NO. E-01345A-03-___)

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A. Background

Q. Please state your name and business address.

A. My name is John H. Landon, and my business address is Two Embarcadero Center, Suite 1750, San Francisco, California, 94111.

Q. What is your current position?

A. I am a Managing Principal and Director of the Energy and Telecommunications practice of Analysis Group, Inc. (Analysis Group) an economic and business strategy consulting firm. My resume is attached to this testimony as Appendix A.

Q. Please outline your educational background.

A. I received a B.A. degree with highest honors from Michigan State University with a major in economics in 1964. I subsequently completed graduate school at Cornell University, where I was awarded an M.A. in economics in 1967 and a Ph.D. in the same field in 1969.

Q. Where were you employed after leaving Cornell University?

A. I served on the faculty of Case Western Reserve University from 1968 to 1973, rising from the rank of assistant professor to associate professor, and on the faculty of the University of Delaware from 1973 to June 1977 as an associate professor.

Q. What subjects did you teach during this period?

A. I taught regulatory economics, microeconomics, industrial organization, antitrust economics, and economic forecasting.

Q. Where were you employed after leaving the University of Delaware?

A. I was employed by National Economic Research Associates (NERA) from 1977 to 1997 first as a Senior Consultant, and, eventually, as a Vice President, a Senior Vice President, and finally as a member of the Board of Directors.

Q. When did you join Analysis Group?

A. I joined Analysis Group in March of 1997.

Q. What has been the nature of your assignments at NERA and Analysis Group?

A. Much of my work over the last twenty-five years has been on issues relating to the application of economic principles to the electric utility industry. I have participated in numerous projects addressing economic and related antitrust issues before the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), the Securities and Exchange Commission (SEC), state regulatory commissions, and federal and state courts.

Q. Please briefly outline your electric utility-related background.

A. I studied regulatory economics both as an undergraduate (Michigan State with Dr. Joel Dirlam) and as a graduate student (Cornell University with Dr. Alfred Kahn). I was one of the graduate assistants who provided research assistance for Dr. Kahn as he wrote his seminal work, *Economics of Regulation*. As a faculty member at

Case Western Reserve University and the University of Delaware, I taught regulatory economics and authored or co-authored several articles and book chapters focused on economic aspects of the electric utility industry. In my more than 25 years of practice as an economic consultant, I have spent the majority of my time on issues involving electric utilities.

B. Prior Experience

Q. Have you previously testified as an expert on the electric utility industry?

A. Yes. I have testified on many occasions before state and federal courts and regulatory agencies on a variety of matters. These matters include: deregulation, affiliate relations, competition and market power, rate making, performance-based regulation, transmission governance, demand-side management, cost allocation and pricing.

Q. Before which state regulatory commissions have you testified?

A. I have provided testimony before the state regulatory commissions of Arkansas, Arizona, California, Delaware, Florida, Illinois, Iowa, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Jersey, New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Texas, Vermont and West Virginia.

C. Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked by Arizona Public Service Company (APS) to provide the Arizona Corporation Commission (ACC) an overview of recent events in the ongoing evolution of the electricity industry that bear on the evaluation of long-term energy supply alternatives. My testimony focuses on evaluating the necessary, but sometimes overlooked, trade-offs in economic efficiencies between two alternative models of long-term electricity supply: 1) vertical integration of generation within the traditional electric utility and 2) contracting for generation supplies with unrelated, and, for the most part, unregulated third parties. I have also been asked to discuss specifically how the current financial condition of some merchant generators and enforcement problems associated with long-term power supply contracts affect the evaluation of efficiency trade-offs.

D. Summary and Conclusions

Q. Please summarize your testimony and conclusions.

A. 1. Cost-of-service regulation in Arizona generally has provided reliable service at relatively low prices. However, regulators and others have sought partial restructuring of traditional regulation in the state in order to capture competitive market efficiencies. These proposals originally included the introduction of a new system of generation supply based on unregulated electricity providers.

2. There are recognized and substantial economic efficiencies from vertical integration, including:

- Coordinating technological and planning interdependencies;
- Conveying efficient prices and cost signals throughout the production process;

- Improving non-price information flow, for example, regarding operating constraints;
- Reducing uncertainty by relying on internally supplied resources;
- Reducing transaction costs; and
- Providing a self supply alternative to supplement, discipline, and hedge the market.

There is also the potential for efficiencies from relying on competition among merchant generators to supply certain long-term resource needs. Regulators need to weigh the trade-offs between these known and potential efficiencies in deciding the appropriate roles of each in meeting utilities' long-term resource needs.

3. Vertically-integrated utilities can benefit from the efficiencies of both vertical integration and the competitive wholesale market by using the latter to supplement the former, and using the former to hedge the latter.

4. The suitability of relying on merchant generation for a utility's long-term resources is a function of four criteria: functioning competitive markets, financially sound counterparties, adequate means of hedging contractual risks, and enforceable contracts. In today's environment, shortcomings in each of these areas increase contractual and operational risks and their associated costs.

5. Regulators should support their jurisdictional utilities acquiring ownership and control of capacity resources if, after appropriately reflecting all economically relevant risks, it represents a cost-effective and reliable way to meet customer requirements.

II. THE VERTICALLY-INTEGRATED UTILITY

A. Historical Perspective

Q. Please discuss the provision of electricity supply prior to the late-1970s.

A. Commencing in the mid-1930s, with passage of the Public Utility Holding Companies Act of 1935, electricity was supplied primarily by vertically-integrated utilities. This structure reflected the widely-held view that, due to economies of scale and scope, the economic efficiencies from vertical integration overwhelmed any competitive efficiencies in electricity supply. Economies of scale occur when there are decreasing average costs with increasing size; i.e., production from larger plants costs less per unit of output. Economies of scope occur when interrelated activities are performed in coordination; i.e., the costs of joint production of a good or service are less than the sum of the individual costs of production.

By the late 1970s, privately-owned utilities accounted for around 75 percent of generating capacity and were regulated by state public utility commissions on a "prudent cost-of-service" basis.[1] That is, for the most part, these firms had the opportunity to earn a regulated rate-of-return from their customers on the depreciated prudent original cost of plant in service, plus recovery of other reasonable expenses. Integrated electric utility operations were generally concentrated in geographically defined service territories, with limited transmission interconnections between them. Transactions between integrated utilities were small relative to self-supply; in short, most utilities were largely self-sufficient.

During much of this period, regulation of prices was based on *ex post* allocations of already incurred costs and expectations of their trends. As a consequence of regulation, incentives to achieve maximum operational efficiency were dulled. When inflation outpaced efficiency improvements, rates tended to rise. Some regulators used ratemaking to implement social goals such as subsidizing designated producers or classes of consumers; this led to further cost increases and introduced additional inefficiencies. Commencing with the effects of the Arab Oil Embargo of 1973-74, deteriorating economic conditions, heightened inflation, and increased interest rates greatly complicated regulated utilities' efforts to build new plants. Problems encountered in constructing nuclear and coal plants during the 1970s and 1980s heightened awareness of the hidden costs of this system of regulation to customers, regulators and utilities—costs that at least partially offset its benefits.

Q. **Did these concerns result in changes in public policy?**

A. Yes. These events led regulators to take a more proactive role in utility cost control. For example, cost disallowances and rates rising less rapidly than costs became more common. In addition, passage of the Public Utility Regulatory Policies Act of 1978 (PURPA) signaled the beginning of a trend that was to lead

[1] In 1979, 97 percent of generation was owned by a combination of privately-owned utilities and publicly-owned utilities. Publicly-owned utilities include municipalities, federal market agencies, rural co-ops,

to greater emphasis on independent generation supplies. PURPA required jurisdictional utilities to contract with certain generators called qualifying facilities (QFs), at avoided costs, i.e., the cost the utility would otherwise have incurred to supply generation. While PURPA encouraged the use of cogeneration and renewable energy, it had the effect of demonstrating the technical feasibility of using third-party generation to meet a significant portion of vertically-integrated utility load requirements. However, the use of administratively forecasted avoided costs as the basis for QF contracts turned out to be very expensive in several states. Administratively determined utility avoided costs, which formed the basis for long-term QF contracts, reflected a static view of technology, as well as the difficult, and relatively short-lived, economic conditions that utilities faced at the time. As economic conditions improved, and technological advances were achieved, long-term QF contracts were revealed as extraordinarily expensive compared with alternative resources.

Later, the Electric Policy Act of 1992 (EPAct), broadened competitive generator eligibility by creating a new class of generators, Exempt Wholesale Generators (EWG), that were exempt from PUHCA requirements. EWGs did not have some of the ownership limitations of QFs, but they also did not enjoy the mandatory utility purchase requirement of PURPA. EPAct also gave FERC the authority to ensure that competitive suppliers had access to markets for their

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and so on.

products. On the basis of this authority, FERC issued Order 888 in 1996, which called for open access to transmission.

Q. Over this same period, was there a change in the perceived level of economies of scale and scope from vertical integration?

A. Yes. The movement away from nuclear power and improvements in the efficiency of small coal plants and combined cycle gas turbines made technical economies of scale less significant in electric generation. Whereas the large nuclear units were around 1,100 megawatts to 1,200 megawatts and required significant upfront investment, today's combined cycle plants are sized as small as 100 to 300 megawatts.[2] In addition, economies of scope from vertical efficiencies, which had been somewhat eroded by the introduction of computer-based information systems, were assumed to be outweighed by the potential benefits of competition.

Q. Were there also changes in the way that vertically-integrated utilities evaluated prospective supply options?

A. Yes. Theoretical models were developed that incorporated competitive generation supply as an alternative to projected future plant additions by vertically-integrated utilities. These models also increasingly took into consideration the ability of utility-owned generation to compete effectively for off-system sales. Electric supply models analyzed the construction of facilities on a regional rather than utility-by-utility basis. Wholesale electric markets increasingly provided

[2] Although individual unit economies-of-scale declined somewhat, there are still significant economies in owning and maintaining multiple units of similar type.

competitive options and opportunity for more efficient operations and planning by vertically-integrated utilities.

B. Trading Off Efficiencies from Vertical Integration and Competition

Q. Are there tradeoffs between achieving the benefits of vertical integration on the one hand and relying solely or primarily on the marketplace on the other?

A. Yes, there are.

Q. Please summarize the trade-off in economic efficiency between 1) utility vertical integration in the provision of new generating resources and 2) relying on the marketplace to provide them.

A. The vertical economies in the generation and delivery of electricity were historically well-known and arose both from economies of scale and scope, including reduced costs of coordination, such as better cost and price signals. Regulation was used to eliminate the market power concerns that otherwise would accompany the single supplier paradigm that resulted.

In contrast, economic efficiencies from wholesale or bulk power supply competition were expected to result from market forces applying competitive pressure on providers 1) to achieve lower costs and develop new products, and 2) to pass these lower costs on to their customers in the form of lower prices and also improved product choices. The bases for the benefits of competitive markets, as a general proposition, are also well-known.

The movement to restructure the electricity industry away from the vertically-integrated model and to introduce wholesale competition in generation supply has rested heavily on the assumption that any increased efficiency from competition would more than outweigh any loss of the old vertical integration efficiencies.

C. Recent Developments

Q. How has the assumption that the efficiency from more competitively-supplied generation would outweigh the loss of efficiency from vertical integration held up in recent years?

A. Recent developments call the benefits of complete reliance on external market alternatives into serious question.

Q. Why is it that contracting for long-term generation supplies from merchant generators may be less economically efficient than self-supply by a vertically-integrated entity?

A. First, the two need not be mutually exclusive. Some merchant generation can be used to supplement self-supply. That being said, cost-of-service regulation has evolved new tools. Mechanisms such as periodic rate freezes and performance-based ratemaking, have evolved in many places to supplement traditional cost-of-service regulation. Indeed, Arizona has utilized each of these regulatory tools in the past decade. These developments preserved the economies of vertical integration while supplying increased incentives to utilities to control generation costs. While these mechanisms may not incorporate all of the same incentives to innovation as competitive markets, taken in combination they appear to have allowed rate reductions in many states, including Arizona. In addition, major increases in new plant efficiency have come from improved generation technology. It is notable that much of this recent innovation in generation has come from competing generating equipment manufacturers, not from independent power suppliers.

It is also noteworthy that competitive markets are not emerging at a uniform pace or in the manner many expected. In some regions, there is uncertainty in bulk power market design and institutions, transmission governance and retail market development. There are also questions as to whether and when markets for electricity will be sufficiently developed to support many of the theoretical benefits of competition. In addition, recent electricity supply market volatility, along with generation expansion in excess of near term market requirements combined with legislative and regulatory uncertainty, have compounded the financial distress of competitive generators. This distress, in turn, calls into question the financial security of long-term energy contracts, jeopardizing the ability of the utility and its customers to realize their benefits. Long-term security through market arrangements is also reduced by increasing difficulties in the enforcement of long-term generation contracts. Default is largely a concern only when contracts turn out favorable to the buying utility and its customers. To the extent that contracts favor the seller, it is not likely that default will become an issue; and, even if it occurs, the utility should be able to easily obtain equivalent or superior replacement supplies elsewhere. In this testimony, I will concentrate my attention on the financial condition of merchant generators and other factors which increase levels of utility risk exposure under long-term contracts.

Q. Please explain.

A. While there is a surplus of physical generation capacity in some regions that may last for several years, much of it is controlled by entities which have suffered significant impairment of their financial condition. In the Southwest, nearly 6,000 MW of new or near-term expected capacity is owned by entities that carry junk bond level credit ratings.[3] As I discuss below, there are substantial risks associated with long-term supply contracts with these entities. Regulators should take account of these risks together with the recent volatility of energy markets and a recent history of enforcement issues with long-term contracts. When weighed against the other advantages of vertical integration, they are likely to find that, in Arizona, a substantial continued reliance on the economic efficiencies of vertical integration outweighs the benefits of a substantial shift to outside procurement and disaggregation at the present time. Under these circumstances, it is reasonable for utilities to integrate capacity into their systems through new construction, purchase or transfer of existing generation from an unregulated subsidiary. The balance of this testimony explores these issues.

[3] Includes Harquahala plant (1,092 MW) which is under construction. According to PG&E National Energy Group if plant is not transferred to lenders or their designees by June 30, 2003, a default will occur. http://www.neg.pge.com/refforts.html (visited June 9, 2003).

Q. How should regulators evaluate the reasonableness of vertically integrating capacity into jurisdictional utilities?

A. Regulators should support their jurisdictional utilities acquiring in ownership and control of capacity resources if, after appropriately reflecting all economically relevant risks, it represents a cost-effective and reliable way to meet customer requirements taking into account all other relevant circumstances.

III. DISCUSSION OF POLICY CHOICES AND CONCLUSIONS

A. Trade-offs Between Vertical Integration and Contracting for Generation

Q. Please discuss the trade-offs between the economic efficiencies from owning generation resources versus acquiring varying degrees of output rights via contract.

A. Comparing the two directly requires considerable care, judgment, and experience. The nature and source of the efficiencies differ. The efficiencies from vertical integration arise primarily from more efficient planning and operational coordination between generation and delivery when the investment, maintenance and operating decisions are made by a single management. In contrast, economic efficiencies from acquiring generation via competitive contracts with unrelated entities depend upon market pressure to provide incentives for wholesale suppliers to offer alternatives that will be both profitable for themselves and cost-effective for the buyer. Vertical integration reduces the reliance on the competitiveness of future markets and utility exposure to the risk of market fluctuations, whereas contracts can only shift some market risks to unregulated market suppliers. The correct balance between the two is a matter for careful judgment—a judgment that may well shift over time.

Q. Please discuss the conditions necessary to realize economic efficiency from wholesale electric market competition.

A. Maintaining competitive pressure requires well-functioning markets and the means to ensure that contractual arrangements are binding and enforceable on financially viable counterparties.

Markets tend to be well-functioning when there are economically sensible and predictable operating and trading arrangements. Today, in the Southwest, these arrangements are not yet fully developed for the supply of electric generation; thus, as in much of the country, the future shape and mechanisms of markets are unknown. As the experience in California has shown, some methods of organizing markets will not lead to economically sound institutions that support competitive and efficient outcomes. At this time, it is unclear whether or when sufficiently well-functioning markets necessary to realize the benefits of competition will be available in Arizona.

In addition, the impaired financial condition of merchant generators has greatly undercut the functioning of markets and has led to increased, even unacceptable levels of counterparty risk for long-term contracts. The likely cost of absorbing or mitigating this risk also must be weighed in evaluating the tradeoff between vertical integration and contracting with third parties.

B. Benefits from Vertical Integration

Q. Please describe the sources of benefits from vertical integration in supply and delivery of electricity.

A. The benefits from vertical integration arise from:[4]

- Technological and planning interdependencies. Where it is most efficient for a good to be passed directly and immediately from one stage to another, the rationale for combining the stages under unitary control is obvious. In electricity, technological and planning interdependencies arise from the need for the system to be continuously in balance between generation, transmission and distribution functions in order to produce and deliver electric service. In competitive markets, the introduction of regionally centralized coordination (such as ISOs or RTOs) is intended to substitute for this source of vertical efficiencies, but gives rise to a new layer of measurement, control and transactions costs. It is necessary, for example, to identify and settle imbalances between participants and to coordinate operation of plants under separate ownership, management and incentives.
- Conveying efficient price and cost signals throughout the production process is difficult. When marginal input and output costs are not observable in or reflected by the market, they cannot

[4] John Landon, "Theories of Vertical Integration and Their Application to the Electric Utility Industry," *Antitrust Bulletin* 28 (1983).

be used to make decisions to adjust production or change inputs. Vertical integration allows the passing of intermediate goods and services between various production stages at marginal cost, as opposed to regulated prices, or at prices contracted for in advance, neither of which will reflect current marginal costs except in the most fortuitous of circumstances. A long-term contract priced at four cents/kWh, for example, may reflect the supplier's marginal costs of 10 cents at peak periods and of 2.5 cents off-peak.

- Improved non-price information flow such as that regarding operating constraints, load and capacity projections, and maintenance plans. Vertical integration enables this information to be used within the organization in a more seamless manner to match loads and resources and to supply customer needs. Where utilities acquire capacity from outside parties they must forecast these factors in advance and draft agreements with their counterparties accordingly. As actual circumstances change, utilities relying on outside resources must coordinate or attempt to negotiate any modifications of contractual constraints in real-time with the needs of customers.

- Reduced uncertainty by relying on internally-supplied resources. Much of this testimony is about the effects of uncertainty regarding the current and future financial well-being of merchant generators and/or on the amount of risk that is inherent in contracts with them. In addition, there are risks associated with evolving markets and the effects of unforeseen developments on contracts and on enforceability of contracts. Relying on internally-supplied resources reduces (although it cannot entirely eliminate) exposure to these risks.

- Transaction costs in vertically-integrated entities generally are significantly lower than in wholesale competitive markets. For example, for a vertically-integrated electric utility that self-supplies generation, acquiring a block of owned capacity entails upfront costs associated with siting and constructing the plant, and perhaps arranging for sales of any excess capacity. Acquisition of supply from outside parties entails repeatedly incurring transaction costs as contracts expire or require renegotiation. Examples of these costs are costs of soliciting resources, negotiating contracts suitable to the utility's anticipated needs, administering contracts and ironing out any disagreements that may arise during the course of the contract. In addition, any contracted energy or capacity that is excess to the utility's needs must be remarketed with or without the participation and cooperation of the seller.

Q. Please describe examples of how these efficiencies are achieved in a vertically-integrated electric utility.

A. The following examples demonstrate how efficiencies are achieved in a vertically-integrated electric utility. This list is illustrative, not exhaustive.

First, internalizing planning for future resource needs of utility retail customers permits planning and investment decisions to be made in a fully-coordinated manner with respect to existing generation, transmission and distribution investments rather than in a piecemeal fashion. In addition, the standard electricity products that are available do not necessarily match utility load shapes as well as a system designed and operated for that purpose.

Second, operating efficiencies are possible when utilities have accurate information on the marginal costs of alternative methods of supplying customer demands and maintaining system regulation and reserves. Accurate marginal cost information enables the utility's resource mix to be dispatched to serve load in the most efficient manner possible given plant operating constraints. When plant operating constraints can be adjusted to improve dispatch and thereby improve overall system efficiency, the vertically-integrated utility has the incentive to do so. A merchant plant owner whose objective is to supply power under already agreed upon terms and conditions may not make similar investments or may make them only if it achieves renegotiation of other aspects of the contract that would be in its favor. In any event, the merchant plant owner would retain the benefit (at least pursuant to the contract terms), in some form, of any investments to improve its plants rather than passing the benefits on to the utility and its customers.

Third, generation plant maintenance can achieve economies of scale and scope if the utility's fleet is sufficiently uniform in type and central in location to allow maintenance crews to service efficiently multiple units and eliminate the need to inventory parts for diverse generation plants constructed by multiple manufacturers. For example, the West Phoenix plant was designed to eventually have multiple, similar units at a single site in order to take advantage of economic efficiencies in maintenance. Although merchant generators can sometimes provide a similarly uniform fleet of generating assets, they may be scattered over many states or have obligations to multiple entities who have differing scheduling requirements. In addition, reliability is enhanced when there are robust maintenance crews available to deal with the consequences of any plant failure.

Fourth, capital improvements can be undertaken when, if and as they are needed to serve load in the most efficient manner. Decision makers also readily can weigh the relative merits of meeting future needs by expanding, upgrading, replacing, retrofitting and/or adding new plant consistent with their obligations to supply service and existing or planned distribution and transmission investments. Thus, the West Phoenix plant, originally an oil-fired generator, was converted to dual fuel capability in the 1980s. Optimal use of expansion and improvement potentials is complicated when different parties will not profit equally and/or at the same time from changes.

Q. Are there other advantages to ownership of generation by vertically-integrated utilities?

A. Yes. These include operational efficiencies (i.e., economies of scope) of scheduling multiple units, coordination to maximize the benefits of off-system sales, and system reliability, as well as economic advantages of financing within the regulated entity.

C. Distressed State of Merchant Generation Industry

Q. Please describe the status of wholesale competitive generation markets today.

A. In some regions, wholesale spot markets for generation appear to some observers to be functioning reasonably well. The PJM Interconnection, NEPOOL, and NY ISO are examples. Consistent with concerns over ongoing litigation, longer-term contract markets in these areas are less fully developed.

In other areas, including the Southwest region that encompasses Arizona, market development has stalled. In some regions, daily and forward markets for physical generation have withered and are not expected to revive to earlier levels any time soon. Broader financial markets to address the risks inherent in competitively supplying electricity are also not well-developed. Last August, Platts reported that as of July 2002, the volume of daily and forward trading at some key hubs declined by up to 70 percent from year earlier levels.[5] Trading on publicly regulated exchanges was halted completely for a time; however, on April 11, 2003, it resumed on NYMEX on a very small scale.

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5 "'Worst is Yet to Come' for Electric Sector, S&P Says as Financials Slide," *Electric Utility Week*, 18 November 2002, 1.

Q. Please describe the financial health of merchant generators today.

A. In general, the financial health of merchant generators has deteriorated significantly over the past two years. The chart in Attachment____JHL-1 provides a graphic illustration of the current credit rating of a number of merchant generators compared with 2001 levels. These generators supplied over 50 percent of all U.S. merchant capacity in 2002. As the attachment illustrates, the credit ratings of every generator have fallen, and more than half have declined from investment grade to junk status. Stock prices also have fallen precipitously. For example, as of the end of May 2003, closing stock prices for Calpine, Reliant and Aquila had fallen from about 80 to more than 90 percent from their highs in mid-2001.

Q. What has led to these declines in merchant generator financial integrity?

A. The primary causes are: 1) a decline in the energy trading business, 2) loss of confidence in the viability of firms in overbuilt and/or immature competitive markets, and 3) the potential future effect of compensation that may be required for past illegal activities.[6] Generation supply is significantly overbuilt in many regions (and may be expected to remain so for several years), resulting in severely depressed price levels. While these conditions may or may not prevail in the Southwest, they do affect the financial well-being of nationally active merchant generators with operations in the region.

[6] Peter Rigby, "Merchant Energy Survival Hangs on the FERC's Blueprint for Market Design, Special Report," *Standard & Poor's Utilities and Perspectives*, Vol. 12, No. 10, March 10, 2003, 6.

Prices are well below those projected during the planning and financing stages for much of merchant plant. They are so low that merchant generators are having difficulty paying the debt associated with construction. These difficulties are triggering creditors' requirements for increased collateral, performance assurances and more onerous financing terms,[7] at a time when internally generated cash flow is often at a historic low. While merchant generators are experiencing difficulty meeting their existing obligations, they will need to refinance around $90 billion in medium-term debt between 2003 and 2006.[8] This perfect storm of adverse conditions continues to undermine the confidence of the financial community in the ongoing viability of the generators themselves. As a result, it is estimated that $200 billion in capitalization evaporated in the U.S. energy sector[9] with additional losses outside of the U.S.

Creditors' requirements for more and more collateral and other performance assurances reduce companies' ability to conduct business on a going forward basis. As a result of merchant generator financial distress, counterparty risk and market uncertainty is very high, leading to further merchant generator financial distress.

Q. In what way are electricity markets immature?

A. At present, the regulated exchanges such as NYMEX are just beginning to re-list forward electricity contracts for some markets. Instead, electricity forward

[7] "Morgan Stanley Sees Banks Hiking Reserves for Troubled Energy Firms," *Electric Utility Week*, 31 March 2003, 1.

[8] "Recalibration of Distressed Assets Begins," *EEnergy Informer*, April 2003, 1.

markets are conducted in an *ad hoc* manner on several privately operated exchanges. These exchanges are not regulated[10] and generally lack independent oversight. Forward contract terms and conditions are not standardized; threshold requirements for participation are not high; and trading volumes are light. Thus, forward contracts are insufficient to supply credible hedges against the increased contract risk presented by merchant generators. Long-term forward contracts are substantially less common. This combination of factors combined with the uncertainty as to future market design and rules discussed above demonstrate that electricity markets are immature.

Q. Why does the distressed condition of merchant generators lead to increased risk for contracting utilities?

A. Reduced credit ratings and falling stock prices have constrained merchant generators' access to capital, and limited financial resources are absorbed by existing projects and obligations. Distressed merchant generators may not have financial resources for bonding or other acceptable direct performance assurances to contracting utilities. Since, as discussed above, it seems likely that counterparty risks for many merchant generators cannot be adequately hedged at the present time, they must be borne by the contracting utility together with its customers if it signs long-term contracts with merchant generation to supply customer needs.

[9] Karl Miller and David Haarmeyer, "Powering Up Private Equity," *Wall Street Journal*, 18 March 2003.

[10] "Use of financial derivatives lags in U.S. electricity market," *Electric Light and Power*, February 2003, 19.

D. Additional Risks of Reliance on Long-Term Contracts for Generation

Q. Are there other reasons to be concerned about over-reliance on long-term contracts with merchant generators at the present time?

A. Yes. Long-term contracts are complex and are subject to interpretation especially in the presence of significantly changing market conditions. As I mentioned previously, electricity markets are continuing to develop, and it is not possible to foresee how rapidly or in which directions they will evolve. In addition, there are currently a large number of litigated matters arising from substantial changes in market conditions. These changes, in turn, have led to significant differences of opinion regarding the interpretation of the terms and conditions of pre-existing contracts. In at least some instances, contracts have been renegotiated, or even terminated, in light of changing circumstances. In contrast to the small adjustments that are normal under long-term contracts, many of these disputes are very large in size, running into the millions, and even billions, of dollars. Thus, even if counterparties are financially viable going forward, contractual provisions negotiated in today's environment for hypothetical deliveries several years from now do not necessarily secure future sources of revenue to ensure the financial viability of merchant suppliers in the future.

Q. Are there other sources of supply uncertainty with regard to long-term contracts with merchant generators?

A. Yes. In addition to developing markets for electricity, environmental regulations are also evolving and can affect plant owners' willingness and ability to keep their plants in operation. An example of this is Southern California Edison's determination to shut down the Mohave generating station in part due to requirements for increased environmental investments. It is instructive that while Edison's Mohave partners have indicated a desire to make the required investments and continue operating, Edison may be able to shut down the entire plant simply by its unilateral refusal to participate. Were Mohave a merchant plant under long-term contract, these actions by Edison may be excusable as *force majeure*. This situation illustrates the vulnerability of even contracts backed by "steel-in-the-ground" to decisions of the counterparty or even its partners over which the purchasing utility may have no control and no effective remedy.

Q. Are you saying that APS should not enter into long-term contracts?

A. No. I am saying that APS and its regulators should weigh all of the risks and benefits of long-term contracting for its generation resource needs against those of plant ownership. APS should seek an appropriate balance of these risks in determining the most advantageous portfolio of resources to serve its customers' needs.

Q. What do you conclude about how the ACC should evaluate vertical integration versus relying on third-party merchant generation.

A. The Commission needs to weigh security of supply and security of price in its deliberations. Prices are low now; however, the ability to bid at a low price does not guarantee an ability or willingness to deliver at that price under future circumstances, even if suppliers are willing to commit to long-term agreements. There are factors related to the future financial viability of competitive suppliers that are beyond the control of either the ACC or the merchant generators themselves. Furthermore, there are limited means in today's markets to hedge the risks of non-performance by merchant generators.[11] Thus, if a buyer of today's long-term contract needs to go back into the market for "cover" in the future, it likely will be at the then current market price, which may very well be above today's contracted price.

Q. Does this conclude your testimony?

A. Yes, it does.

[11] For example, on June 13, 2003, NRG Energy discontinued deliveries to Connecticut Light and Power pursuant to a ruling by the U.S. Bankruptcy Court for the Southern District of New York. FERC is scheduled to review this matter.

Appendix A

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Dr. Landon has served as an economic consultant to the electric utility, coal, and uranium industries for over 20 years. His consulting experience has been wide-ranging and includes analysis of deregulation, strategic planning, competition, ratemaking, transmission governance, performance-based regulation, statistical benchmarking, demand-side management, cost allocation, and pricing. Dr. Landon has testified more than 100 times before federal district courts, state courts, the Securities and Exchange Commission, the Federal Energy Regulatory Commission, and various state commissions, and has prepared numerous expert reports and affidavits. He has authored or co-authored more than 20 articles published in academic and trade journals, two book chapters, and several monographs.

His litigation work has involved damages assessments, forecasting, merger analysis, market definition and market power, valuation, antitrust liability, cost allocation, and pricing.

Prior to joining Analysis Group, Inc., Dr. Landon was Senior Vice President at NERA, Inc. Previously, he held positions as Associate Professor of Economics at the University of Delaware and Case Western Reserve University. Dr. Landon holds a Ph.D. in Economics from Cornell University.

PROFESSIONAL ACTIVITIES

Member of the Governor of Delaware's Economic Advisory Committee

Director of the Center for Policy Studies at the University of Delaware

A Director of the Delaware Econometric Model Group

Senior Research Associate in the Research Program in Industrial Economics at Case Western Reserve University

Member of the American Economic Association

Associate Member of the American Bar Association

TESTIMONY PROVIDED FOR THE FOLLOWING CLIENTS:

- **Public Service Company of Oklahoma**
  On behalf of Public Service Company of Oklahoma, Cause No. PUD 200200038, November 5, 2002, (Direct Testimony), January 14, 2003 (Rebuttal Testimony) and January 23, 2003 (Surrebuttal Testimony).

- **Commonwealth Edison Company**
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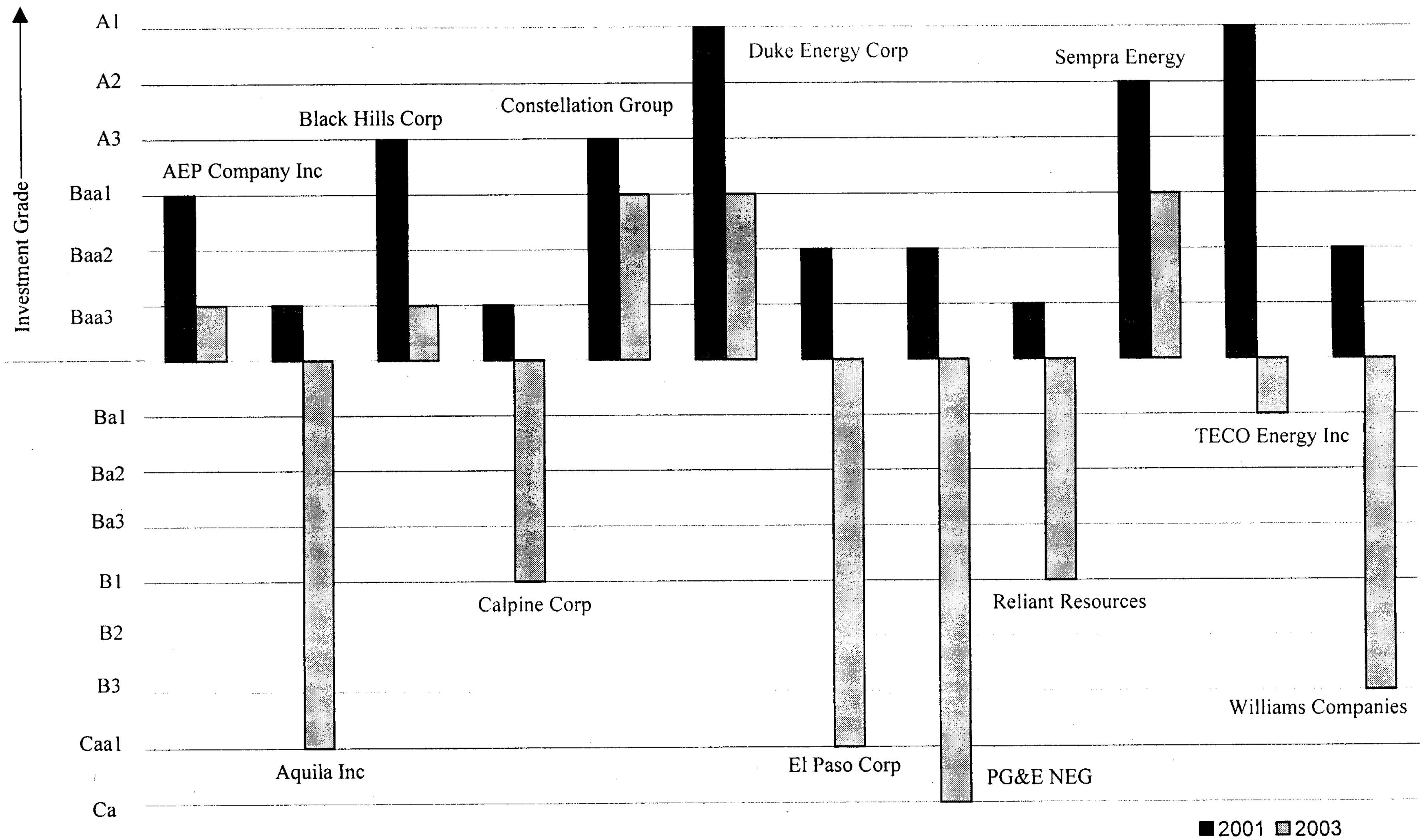
Attachment__JHL-1

Selected Energy Company Credit Ratings, 2001 and 2003
(Moody's Ratings on Senior Unsecured Debt as of June 20, 2003)



Sources: Companies' Press Releases and Moodys.com

Notes:

1. In 2001, UtiliCorp United owned 80% of Aquila Inc; The 2001 rating is for UtiliCorp United.
2. Long-Term Senior Implied Rating is used for Reliant's current rating.

APS-10

EXHIBIT
APS-10
admitted

DIRECT TESTIMONY OF ALAN PROPPER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-___

June 27, 2003

Table of Contents

DIRECT TESTIMONY OF ALAN PROPPER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-   )

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Alan Propper. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Arizona Public Service Company ("APS" or "Company") as Director of Pricing. I am responsible for establishing and administrating APS tariffs and contract provisions that are under the jurisdiction of the Arizona Corporation Commission ("ACC" or "Commission") or the Federal Energy Regulatory Commission ("FERC").

Q. WOULD YOU DISCUSS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE?

A. My background and experience are set forth in Appendix A to this testimony.

Q. WERE THIS TESTIMONY AND THE ACCOMPANYING ATTACHMENTS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes, they were.

Q. ARE YOU SPONSORING ANY STANDARD FILING REQUIREMENTS ("SFR") SCHEDULES?

A. Yes. I am sponsoring required SFR Schedules G, and H, and portions of SFR Schedules B-1, B-2, C-1, and C-2, as well as the rate schedules portion of APS' retail tariff. Although not specifically required by the SFR, I am also sponsoring some additional schedules that have been designated as Schedule GJ (Attachment

AP-1), Schedule GE1 (Attachment AP-2), Schedule GE2 (Attachment AP-3), and Schedule GE3 (Attachment AP-4) and are attached to my testimony.

Q. WOULD YOU SUMMARIZE YOUR TESTIMONY?

A. My testimony addresses two general areas. The first area discusses the cost-of-service study prepared to Functionalize, Classify, and then Allocate test year costs and revenues first between wholesale and retail customers and then to the various classes of retail service. It is this cost allocation study that allows me to determine the rate of return produced by each class and subclass of customer, as well as the unit costs needed to be expended to provide service to each customer grouping. The second area discusses the rates and related service provisions being proposed to recover the costs of providing service to our customers.

II. COST-OF-SERVICE

Q. WAS AN EMBEDDED CLASS COST-OF-SERVICE STUDY USED IN THE DEVELOPMENT OF APS' PROPOSED RATES?

A. Yes. APS' proposed rates are based on an embedded and fully allocated cost-of-service study, with calendar year 2002 as the test period, as a major input for designing the proposed rates. The study results provided both rates of return for the customer classes as well as a Functionalization, Classification, and Allocation of costs.

Q. WAS THE USE OF A 2002 TEST YEAR SUITABLE FOR THIS COST-OF-SERVICE STUDY?

A. Yes. A test year utilizing 2002 data provides the most recent calendar year financial and operational information, and is consistent with the Company's revenue requirements. Therefore, I believe it is appropriate to be used as the basis for performing an accurate cost-of-service analysis. Although a future test year is more reflective of the period in which the proposed rates will be in effect, such a future test period is not generally used in Arizona. However, the Company's analysis does include a number of pro forma adjustments to the 2002 test year to reflect known changes and to better match the costs and revenues with the period in which the proposed rates will be in effect, as well as other adjustments to normalize the test period.

Q. WHAT DO YOU MEAN BY NORMALIZING THE 2002 TEST YEAR INFORMATION?

A. Normalization refers to eliminating the effect of conditions or situations that would not ordinarily occur or be expected to occur in a normal test year, or that recur periodically but should be averaged out over a period of years. The purpose of normalization is to produce a test year that will be generally representative of conditions that would exist during the period in which the proposed rates would be in effect. For example, if APS experienced some unusual expense during the test year, such as inordinately high storm damage, an adjustment to reflect more normal conditions would be appropriate.

Q. HOW DO YOU TREAT PRO FORMA AND NORMALIZATION ADJUSTMENTS TO THE TEST YEAR IN YOUR COST-OF-SERVICE STUDY?

A. APS witness Donald G. Robinson's testimony sponsors a number of pro forma adjustments that were incorporated into the adjusted 2002 test year cost-of-service study. Mr. Robinson's Attachments DGR-4 and DGR-5 list, by rate base and expense category, the monetized amount of each proposed pro forma adjustment. These amounts were then Functionalized, Classified, and Allocated to the appropriate retail and wholesale customer classes as part of the process in performing the cost-of-service study. Please note that in Mr. Robinson's testimony, he distinguishes between several types of pro forma adjustments, in addition to normalizing adjustments, depending on the basis for making the adjustment. However, for purposes of performing a test period cost-of-service analysis, whether an adjustment is appropriate because of normalization or as a result of a change that has occurred or will occur is not relevant, and thus I refer to all test year adjustments generically as pro forma adjustments. The adjusted 2002 test year cost-of-service study reflects all the proposed pro forma adjustments.

Q. WOULD YOU DISCUSS THE DEVELOPMENT OF THE EMBEDDED COST ALLOCATION STUDY?

A. This study was prepared using industry accepted cost-of-service principles of Functionalization, Classification, and Allocation and is generally consistent with historical APS practices.

"Functionalizaton" refers to the process of attributing a particular Rate Base or Expense item to a particular function, namely Production, Transmission, or Distribution, in the provision of electric service. An easy and obvious example is the assignment of the costs of building and operating one of the Company's power plants to the Production function.

"Classification" refers to the process of determining the factor or factors that compel the magnitude of the cost. For example, if a cost is driven by the amount of energy consumed, it is classified as Energy; if a cost is driven by the rate at which energy is consumed, it is classified as Demand; or if a cost is driven by the number of customers taking service on the APS system irrespective of either demand or energy utilized, it is classified as Customer.

"Allocation" occurs once a cost has been functionalized and classified. This is the process in which allocation factors are applied to spread the costs to particular jurisdictions, customer classes, and rate schedules. A simple example is the allocation of energy related costs by kilowatt-hour ("kWh") consumption.

In this study, the numerous Expense and Rate Base items that comprise APS' costs were grouped into major categories, such as Plant in Service or Operating & Maintenance Expense. Each of these categories was first functionalized into Production, Transmission, or Distribution related costs, then classified as Demand, Energy, or Customer related. Allocation factors based on kilowatts, kilowatt-hours, and number of customers were then developed so that allocations of the functionalized and classified costs could be made to the federal and state jurisdictions and to the various retail customer classes and sub-classes. When necessary, procedures were used to reflect unusual or changing circumstances, as discussed later in my testimony.

Q. WHAT BASIS IS USED TO ALLOCATE FUNCTIONALIZED COSTS BETWEEN JURISDICTIONS AND AMONG CUSTOMER CLASSES?

A. Production related and Transmission related assets, and their associated costs, are generally designed and built to enable the Company to meet its system peak load. Correspondingly, they are allocated on the basis of the average of the system peak demands occurring in the months of June, July, August, and September ("4CP"). Distribution plant, unlike Production and Transmission plant is generally designed to meet a customer class' peak load, which may or may not be coincident with the system peak load. Thus, allocations of costs related to Distribution substations and primary Distribution lines are made on the basis of non-coincident peak loads ("NCP"). Allocations of costs related to Distribution transformers and secondary

Distribution lines are made on the basis of the summation of the individual peak loads or demands of all customers within a particular customer class ("ΣNCP").

Q. WHAT IS THE BASIS OF THE "ALL OTHER" OR NON-JURISDICTION SEGMENT OF YOUR COST-OF-SERVICE STUDY?

A. The "All Other" segment, which appears as a separate column in the cost-of-service study, represents the Rate Base, Expenses, and Revenues associated with service to long-term firm FERC jurisdictional resale customers that APS serves, as well as firm wheeling services APS provides to a number of FERC jurisdictional entities. Since APS utilizes Company facilities in order to fulfill these obligations, I have allocated a portion of APS Production, Transmission, and Distribution facilities to these non-jurisdictional customers in the same manner as I would to our classes of retail jurisdictional customers in preparing this cost-of-service study.

Q. WOULD YOU EXPLAIN THE USE OF REVENUE CREDITS IN THE COST-OF-SERVICE STUDY?

A. In addition to the transactions described for inclusion in the All Other column depicted in the cost-of-service study, APS makes off-system sales to third-party entities. In making such off-system transactions, APS resources may be utilized. In order to be certain that the benefits of such transactions flow through to our retail customers, the revenues derived from these transactions, which more than cover the incremental costs associated with producing or acquiring the required energy, are allocated to all customers. Thus, the margin or profit that APS realizes from such non-retail transactions is attributed to each class through the Revenue Credit, which benefits all customers by lowering their otherwise determined revenue requirement.

Also treated as Revenue Credits are the somewhat unpredictable and non-firm short-term Transmission for Others transactions, and a number of small items such as Rent from Electric Property, Forfeited Discounts, Miscellaneous Service Revenues, sales to Rate E-36 customers, and Other Electric Revenues.

III. SPECIALLY HANDLED COST ITEMS

Q. HAVE ANY NEW OR SPECIALIZED PROCEDURES BEEN USED IN PERFORMING THIS COST ALLOCATION STUDY?

A. Yes. As a result of FERC initiatives to foster wholesale competition, FERC's Transmission pricing principles, and recent FERC decisions affecting APS, some degree of jurisdictional authority over the Transmission component of bundled retail rates in states having mandated retail access programs has been claimed by FERC. This circumstance has an impact on the Transmission related costs within the parameters of a cost-of-service study, and therefore Transmission related costs were treated in a different manner than has been done historically.

Q. WOULD YOU EXPLAIN HOW TRANSMISSION COSTS WERE TREATED IN THE COST-OF-SERVICE STUDY?

A. A November 30, 2000 FERC Order requires APS to acquire Transmission related services used to supply electric power and energy to Scheduling Coordinators for APS' Standard Offer retail customers under the provisions of APS' own Open Access Transmission Tariff ("OATT"). The requirement for having a Scheduling Coordinator is stated in the Protocols of the Arizona Independent Scheduling Administrator ("AISA"), and is further supported in the Commission's Competition Rules. Thus, from a cost allocation perspective, the revenue requirement for such Transmission services is treated as an expense derived from the FERC jurisdictional rates expressed in our OATT.

Specifically, APS' retail merchant function, which serves as the Scheduling Coordinator for Standard Offer customers and is responsible for generating or purchasing power for APS' Standard Offer retail customers, has been required to pay APS' OATT rates for Transmission and Ancillary Services needed to deliver electric power and energy to these APS retail customers. Those dollars were booked as both Transmission revenue and as an offsetting Transmission expense during the test period.

Q. HOW DID YOU DEVELOP COSTS FOR THE TRANSMISSION FUNCTION IN THE COST-OF-SERVICE STUDY?

A. For purposes of this cost-of-service study, I first computed Transmission related Rate Base and Expense for the test period. This was accomplished by first performing a complete unadjusted 2002 cost-of-service study which included identifying Production, Transmission, and Distribution costs using the traditional cost-of-service methodologies I discussed previously. From this study, total Transmission costs, both Rate Base and Expenses, were isolated and used as the basis for determining how much of the Company's costs were related to providing Transmission services. Finally, these Transmission related costs were removed from the cost-of-service study via pro forma adjustments, as indicated in Mr. Robinson's testimony and attachments.

Since total Transmission costs are being treated as an operating expense for purposes of this study, this expense was developed by aggregating the following transactions: 1) retail related Transmission expenses were calculated by multiplying adjusted test year retail billing determinants by the applicable Transmission rates in Part IV of APS' OATT; 2) test year revenues from pre-OATT firm wholesale wheeling transactions were treated as an expense; and 3) the test period billing determinants for post-OATT firm wheeling transactions were multiplied by APS' OATT rate for firm point-to-point Transmission service of $1.43/kW/month. These OATT expense items were then included in the cost-of-service study via a pro forma adjustment. I will discuss the proposed recovery of Transmission related costs in the Rate Design section of my testimony.

Q. ARE ANCILLARY SERVICES TREATED IN A SIMILAR MANNER?

A. Yes. FERC views Ancillary Services as Transmission related services, and therefore a pro forma adjustment was made to remove associated rate base and expense items from the cost-of-service study. Since several of the six Ancillary Services are Production related, for cost-of-service purposes, I first identified which APS generating units were used in providing a specific Ancillary Service. I then determined what portion of the total MWh produced during the test period by that unit was for that specific Ancillary Service. This percentage was then used as the basis for allocating that portion of a particular unit's test period costs to that specific Ancillary Service.

Once the appropriate Production related cost associated with each pertinent Ancillary Service was determined, it formed the basis of the Ancillary Services component of the Transmission pro forma adjustments discussed above. Note that the proposed Transmission pro forma adjustments are comprised of two components, Transmission and Ancillary Services. The amount of this Ancillary Services component was then subtracted from Production related costs that were to be allocated to the various customer classes. Consistent with the treatment of Transmission costs as an expense for purposes of the cost-of-service study, Ancillary Service related costs are treated similarly. I derived the applicable Ancillary Service expense assigned to retail customers by multiplying the adjusted

2002 test period retail billing determinants times the applicable rates for Ancillary Services contained in Part IV of APS' OATT.

Although "Must Run" is not specifically considered a FERC Ancillary Service, FERC nevertheless considers it a Transmission related service and has also asserted its jurisdiction over Must Run charges. In developing the cost-of-service study, I specifically excluded the appropriate costs associated with Must Run so they would not be included in our Standard Offer retail rates. At such time the Company elects to assess and collect specific Must Run charges, we will be required to modify our OATT to include these charges, and make the appropriate filing with FERC pursuant to their Order in Docket No. ER01-173-000, issued November 30, 2000.

Q. DOES YOUR COST ALLOCATION STUDY CONTAIN ANY TERMS OR ITEMS THAT HAVE NOT TRADITIONALLY BEEN DIRECTLY ADDRESSED IN COST-OF-SERVICE?

A. Yes. The study reflects treatment of System Benefits and Regulatory Assets.

Q. WOULD YOU EXPLAIN WHAT IS MEANT BY SYSTEM BENEFITS?

A. System Benefits refer to the costs associated with such items as renewable resources, demand side management, nuclear plant decommissioning, nuclear fuel disposal, customer education, and other items that may be included in rates, as specified by the ACC. For the purposes of this cost allocation study, System Benefits costs have been separately accumulated and unbundled so they can be identified for rate design purposes.

Q. WOULD YOU EXPLAIN WHAT IS MEANT BY REGULATORY ASSETS?

A. Regulatory Assets are expenses incurred by APS on projects, equipment, and financial obligations for the benefit of its customers that have not as yet been paid for by its customers. Pursuant to ACC Decision Nos. 59601 and 61973, the ACC authorized the collection of certain of these expenses from customers through electric rates over an extended period of time, thereby smoothing out their recovery in customer bills. Examples of Regulatory Assets are deferred income tax payments, accrued coal mine reclamation costs, and deferred financing costs for specific generation units. For purposes of this cost allocation study, Regulatory Assets have been separately identified as a stand-alone function and have not been assigned to Production, Transmission, or Distribution.

Q. HOW HAVE YOU HANDLED FRANCHISE FEES?

A. For the purpose of the cost-of-service study, as well as rate design, expenses associated with Franchise Fees and associated revenues have been excluded from the cost-of-service study and will be treated as a rate surcharge or an addition to be passed through to our customers, much the same as Sales Tax. This is discussed more fully in my testimony under Rate Design.

Q. HAVE YOU CALCULATED THE COSTS, RATE BASE, AND RATE OF RETURN BASED ON THE 2002 ADJUSTED TEST YEAR?

A. Yes. In addition to establishing the Production, Transmission, and Distribution functions and the Demand, Energy, and Customer classifications for each class of retail business, the rate of return for each class under test year and proposed rates appear in the SFR "G" Schedules associated with this rate application.

IV. "G" SCHEDULES

Q. MR. PROPPER, WOULD YOU DESCRIBE THE SFR "G" SCHEDULES?

A. Yes. The following is a summary of these Schedules:

- SFR Schedule G-1 shows the rate-of-return at existing rates by customer class, based on the adjusted 2002 test year cost-of-service study.

- SFR Schedule G-2 is similar to Schedule G-1 except this Schedule reflects returns by class that would result under APS' proposed rates in this proceeding.
- SFR Schedule G-3 shows the $ and % amount of adjusted Original Cost Less Depreciation ("OCLD") Rate Base costs allocated to each retail customer class.
- SFR Schedule G-4 shows the amount of operating Expenses allocated to each retail customer class.
- SFR Schedule G-5 shows the $ amount of functionalized adjusted Rate Base allocated to ACC jurisdictional customers.
- SFR Schedule G-6 shows the amount of functionalized adjusted operating Expense allocated to the ACC jurisdictional customers.
- SFR Schedule G-7 lists all applicable allocation factors used in preparing the 2002 test year cost-of-service study.

Q. DO YOU HAVE ANY ADDITIONAL SCHEDULES RELATED TO THE COST-OF-SERVICE STUDY THAT YOU ARE SPONSORING?

A. Yes. The following filed additional Schedules relate to the study:

- Schedule GJ is a summary of the cost-of-service study showing the jurisdictional separation of Rate Base costs, Revenues, and operating Expenses.
- Schedule GE1 is a summary of the cost-of-service study showing, by retail customer class, the allocation of total ACC allocated Rate Base costs, Revenues, and operating Expenses and the rate-of-return for each major customer class.
- Schedule GE2 is a summary of the cost-of-service study showing, by each

General Service subclass, the allocation of Rate Base costs, Revenues, and operating Expenses and the rate-of-return.

- Schedule GE3 is a summary cost-of-service study showing, by each Residential subclass, the allocation of Rate Base costs, Revenues, and operating Expenses and the rate-of-return.

Q. BASED ON THE RESULTS OF YOUR ADJUSTED TEST YEAR 2002 COST-OF-SERVICE STUDY, WHAT CONCLUSIONS HAVE YOU MADE?

A. I believe it is apparent from the "G", GJ, and GE Schedules that there are significant disparities in the rates of return that the different customer classes are providing to the Company. In addition, but less apparent from the summaries, is my conclusion that the rate designs themselves, separate and apart from their individual levels, do not fully reflect the Demand, Energy, and Customer unit costs relationships as would be dictated by strictly cost based rate design. These conclusions need to be considered as one of the inputs for the proposed rate designs.

V. RATE DESIGN

Q. WERE APS' PROPOSED RATES DEVELOPED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, my department personnel and I developed the proposed rates and schedules. However, we did receive input from our Customer Service department in developing the proposed rate schedules.

Q. WOULD YOU DESCRIBE THE OVERALL OBJECTIVES OF THE PROPOSED RATE DESIGNS?

A. In developing our proposed rate schedules, we had several objectives in mind. First, the proposed rates were developed to meet APS' revenue requirement.

Second, it was our desire to improve cost tracking, both as to rate level and design of the pricing components, of our various rates. Third, we endeavored to better unbundle the rates in conformance with the objectives established by the ACC in the Commission's Electric Competition Rules.

Q. WOULD YOU EXPLAIN WHAT YOU MEAN BY "IMPROVE THE COST TRACKING OF THE VARIOUS ELEMENTS OF OUR RATES?"

A. It has been many years since APS has revised the basic structure of its retail rates. The more recent rate changes have generally been made on the basis of "across the board" percentage changes as a result of rate case settlements. This has resulted in some rate distortions that have taken our rates away from tracking costs, both as to rate level and rate design. The process of unbundling our retail rates also identified instances in which our rates were obviously not fully following costs. Our proposed rates address, at least to the degree I believe practical, this concern. As will be discussed, this concern was addressed through redesign of the rates themselves, and not by varying the proposed overall percentage increase to each of the major customer classes.

Q. WOULD YOU DESCRIBE THE PROCESS USED TO DEVELOP THE PROPOSED RATES?

A. The starting point in the rate design process is the cost-of-service study discussed earlier in my testimony. The cost-of-service study allocates the costs of providing service to each of the major classes of customers, as well as various sub-classes and rate schedules. If the cost-of-service study was the only determinant for setting rates, each rate classification would recover APS' proposed rate of return and all rate schedules would be expressed in the form of unit costs and expressed as Demand Charges, Energy Charges, and Customer Charges. However, many other considerations were taken into account in designing the proposed rates, which resulted in individual rate schedules that differ from the overall proposed rate of return and rate designs that differ in appearance and application.

Q. OTHER THAN THE COST-OF-SERVICE STUDY, WHAT OTHER FACTORS WERE CONSIDERED WHEN DESIGNING THE PROPOSED RATES?

A. We considered several other factors. Among the most important were rate stability and continuity. For this reason, the major classes of customers—Residential, General Service, Irrigation, Street Lighting, and Dusk to Dawn—have each been given a percentage increase that is approximately the same as the overall requested increase. In addition, the individual rate schedules have been designed to depart from strict cost-of-service adherence as necessary, so that differences in the increases that individual customers will experience will be moderated to the extent reasonable. An additional consideration in developing the proposed rate schedules was customer understandability and ease of administration. In other words, we attempted to simplify the specific rates and the presentation of the tariff in general. Consideration of these factors is in conformance with the traditional or classical aspects of rate design.

Q. HAVE THE PROPOSED RATES BEEN UNBUNDLED TO SHOW THE INDIVIDUAL COMPONENTS OF COST RECOVERY?

A. Yes, to the degree practical or possible. Moving from bundled rate schedules to unbundled and more cost-based rate designs represents a significant change from current and previous rates. We attempted to mitigate the problems and confusion related to this transition to the unbundled rate formats by carefully considering the content and format of the rate schedules, as well as the expected appearance of the resulting bills.

Q. WAS THE COST-OF-SERVICE STUDY USED IN DEVELOPING THE PRICING OF REVENUE CYCLE SERVICES IN THE UNBUNDLED PROPOSED RATES?

A. Revenue Cycle Services include metering, meter reading, and billing which, under certain circumstances as approved by the Commission, can be rendered to the customer by a provider other than APS. In such instances, when a customer elects an alternative provider, a cost (or price credit) must be developed so that APS is not charging the customer for these services. The cost-of-service study was used to develop pricing for these unbundled Revenue Cycle Services costs for each unbundled rate schedule.

Q. DOES THIS MEAN THAT APS IS WILLING TO IGNORE THE LOWER DECREMENTAL COST OF REVENUE CYCLE SERVICES WHEN PROVIDING A CREDIT TO A CUSTOMER WHO TAKES SUCH SERVICES FROM A PROVIDER OTHER THAN APS?

A. Yes, but only for purposes of this rate case. The decremental cost of Revenue Cycle Services, such as billing, is the actual cost saved by APS if an alternative provider, such as a competitive Electric Service Provider ("ESP"), provides that service to an APS customer. In the short run and for small increments of customers, this decremental cost is very low. In the example of meter reading, it amounts to only the cost of one stop in a meter reader's entire route.

Using the embedded cost-of-service study for establishing the cost savings to APS, as is being proposed, does overstate these costs and therefore the price credit. However, given the general lack of interest in retail Direct Access to date and virtually no recent interest by ESPs in providing specific Revenue Cycle Services, the burden the higher credit would impose on other APS customers is minimal. I do not believe the dollar amounts involved to be great enough to justify preparing the detailed studies needed to determine the decremental costs, though such an approach would philosophically be the preferred method. It is quite possible that the Company may wish to revisit this matter in the next rate case if our experience with others providing such services warrants a reexamination.

Q. DID UNBUNDLING THE RATES AND, IN PARTICULAR, REVENUE CYCLE SERVICES IMPACT BASIC SERVICE CHARGES?

A. Yes. Revenue Cycle Services are fixed Customer related costs that should be collected in the fixed Basic Service Charge component of a rate. Including recovery of even a portion of these costs through the variable Energy or Demand components of a rate not only unduly varies from cost tracking and causation, but also creates major design, administrative, and customer equity problems. This situation becomes most noticeable when establishing Direct Access rates that are to correspond to the unbundled Standard Offer rates. For these reasons, the Basic Service Charge of each rate was adjusted to be certain that, at the very least, no less than Revenue Cycle Services costs would be recovered in this charge.

In addition, it should be noted that the Basic Service Charge for many rates will now be stated as a daily charge. This is for the purpose of recognizing that the number of days in a billing month changes from month to month, and to facilitate billing and avoid proration when customers do not receive service from the Company or service on the same rate for the full billing month.

Q. WOULD YOU DESCRIBE THE RATE DESIGN CHANGES YOU HAVE MADE WITH REGARD TO THE RECOVERY OF TRANSMISSION RELATED COSTS?

A. For the reasons I mentioned in my discussion of the cost-of-service study, we have changed how we treat Transmission costs, as well as Ancillary Services and Must Run, when compared to our previous traditional cost-of-service studies. That portion of the FERC jurisdictional Transmission cost that will be passed on to retail customers is based on the average charge incurred by the Scheduling Coordinator for the APS retail load. We are proposing that a Transmission Cost Adjustment Clause, similar to the Power Supply Adjustment Clause ("PSA") that APS proposed last year, be instituted. This will enable us to pass on the Transmission costs incurred to supply electric power to the retail customers in a timely manner and on a dollar for dollar basis. Once a Regional Transmission Operator ("RTO") or its equivalent is operating, APS' Scheduling Coordinator will become a purchaser of Transmission service from the RTO, and the rates and proposed adjuster will pass on FERC regulated RTO charges as an expense for Transmission service.

VI. TRANSMISSION COST ADJUSTMENT CLAUSE

Q. WOULD YOU DESCRIBE THE PROPOSED TRANSMISSION COST ADJUSTMENT CLAUSE?

A. The clause appears as Rate Schedule TCA-1. As with any such adjustment clause, it is designed to track changes occurring in a specific cost, whose base amount is included in the retail rates. In this particular instance, the clause relates to specific costs incurred by the Scheduling Coordinator for procuring Transmission related services for retail customers under APS' or some other Transmission provider's OATT or contract.

Each of our proposed Standard Offer rates includes a base Transmission charge, reflecting the Transmission related expenses I previously described. The proposed Transmission Cost Adjustment ("TCA") factor will track the actual incurred costs of providing these Transmission related services compared to the cost inherent in base retail rates. The TCA factor will be credited or debited to customers' bills each month as a per kWh Energy charge. The factor will be the same for all affected Standard Offer customers and will be adjusted once each year.

The TCA methodology consists of four components:

- A base level Transmission related charge component inherent in the Standard Offer retail rates,
- A monthly Transmission Cost Component Factor ("TCCF") charged to customers,
- A Balancing Account, and
- An Amortization Charge that may be implemented to reduce the size of the Balancing Account.

Q. WILL THE TCA APPLY TO DIRECT ACCESS CUSTOMERS?

A. No, but that does not mean Direct Access customers will not pay for these costs. The Scheduling Coordinator for a Direct Access customer will be directly charged the OATT charge by APS under its FERC tariff. The extent and manner by which such OATT charge is passed along to the Direct Access customer will be determined by the load serving ESP's contract with its customer.

Q. WOULD YOU DESCRIBE HOW THE TCCF WILL BE COMPUTED?

A. Basically, the TCCF is computed by comparing the twelve-month Transmission cost to the base Transmission charge. For example, if the twelve-month actual Transmission related average cost is 5.0 mills per kWh and the base Transmission charge is 4.7 mills per kWh, the TCCF would be 0.3 mills per kWh. The TCCF can be positive or negative.

Q. WOULD YOU PLEASE DESCRIBE THE PURPOSE OF THE BALANCING ACCOUNT?

A. The Balancing Account accumulates dollars associated with under-collection or over-collection from the application of the TCA. The TCCF will be adjusted once each year after the final bills for Transmission service for the previous calendar year are received. The adjusted TCCF will then be applied for the next 12 months. Thus, there is a slight mismatch between the time periods of cost incurrence and revenue collection. From time to time, APS may make a filing with the ACC to obtain approval to amortize any TCA account balance and reset the Balancing Account to zero. It is intended that interest will be accrued based on the three-month commercial paper rate. The interest will be credited for both positive and negative Balancing Account accumulations.

Specific details regarding the operation and administration of the TCA will be set forth in a Plan for Administration to be approved by this Commission subsequent to adoption of the TCA.

Q. WHAT ACC ACTIONS WILL BE REQUIRED TO IMPLEMENT CHANGES ONCE THE TCA MECHANISM IS APPROVED?

A. APS will make informational filings with the ACC annually. These filings will include the calculations required for developing an updated TCCF for the subsequent year, invoices for Transmission and Ancillary services rendered to the APS retail Scheduling Coordinator, and the Balancing Account calculations. Must Run information will also be included when applicable. Each filing will include a revised tariff sheet indicating the revised TCCF, which would be effective upon filing or on such date as is indicated in the filing. Formal Commission action would only be required if a filing is made by APS requesting establishment of or revision to the Amortization Charge.

VII. RECOVERY OF OTHER COST ELEMENTS

Q. WOULD YOU PLEASE DESCRIBE HOW FRANCHISE FEES PAID TO MUNICIPALITIES WILL BE RECOVERED?

A. We are proposing that these Franchise Fees be removed from base rates. Franchise Fees would instead be collected via a separate charge on customers' bills, similar to the method used to collect Sales Tax.

Q. WHY ARE YOU PROPOSING THIS CHANGE TO THE FRANCHISE FEE COLLECTION METHOD?

A. First, it brings us in line with the rest of the utility industry and, in particular, other electric utilities in Arizona. Second, it is simply a fairer method. Franchise Fees are effectively a tax on APS levied by the municipalities in which we serve. Currently, Franchise Fees are recovered from all customers through base rates, regardless of the political subdivision in which they reside. Under our proposed method, customers in Phoenix will only pay the costs associated with the Phoenix Franchise Fee, Flagstaff ratepayers will pay the Flagstaff Franchise Fee, and so forth. Those customers outside of municipal franchise areas will no longer pay for Franchise Fees through the base rates. Simply stated, our proposed method assures the correct and fair relationship between Franchise Fees imposed by municipalities and collection of these fees from the retail customers residing in the respective municipalities.

Q. ARE THERE ANY OTHER COST ELEMENTS THAT WOULD RECEIVE RECOVERY TREATMENT OUTSIDE OF THE BASE RATES?

A. Yes. In addition to costs to be recovered through the PSA and the Transmission Adjuster, Franchise Fees, Regulatory Assessments, and Sales Tax, there are those costs associated with the Environmental Portfolio Surcharge as set forth in Rate Schedule EPS-1, the Competition Rules Compliance Charge as set forth in Rate

Schedule CRCC-1, the Returning Customer Direct Assignment Charge as set forth in Rate Schedule RCDAC-1, and the System Benefits Adjustment Charge as set forth in Rate Schedule SBAC-1.

Q. HAVE YOU ESTABLISHED THE BASE CHARGES FOR THE VARIOUS SURCHARGES OR ADJUSTMENT CLAUSES?

A. Yes. Based on the cost-of-service study, bases have been established for the PSA, CRCC, and the TCA, and are stated in the appropriate rate schedules. The mechanisms for charges under the RCDAC and the SBAC are to be established in Docket No. E-01324A-02-0403.

Q. WOULD YOU DISCUSS THE NOTICE THAT APS WOULD PROVIDE TO CUSTOMERS OF CHANGES IN THE FACTORS AND CHARGES RELATED TO THE PSA?

A. Yes. Although a decision has not yet been made in the docket for the PSA, APS said it would discuss in this rate case the notice to be provided to customers for changes in the factors and charges related to the PSA. Notice for changes to the Power Cost Component Factors, which will be adjusted semiannually, or in cases where the Balancing Account is amortized and reset will be provided by messages printed on the bill, bill inserts, or separate letters from the Company to its customers. In any case, notice would be provided prior to implementing the change in the factors and charges related to the PSA.

VIII. <u>RESIDENTIAL RATE SCHEDULES</u>

Q. WOULD YOU PLEASE GIVE A GENERAL DESCRIPTION OF THE EXISTING RESIDENTIAL RETAIL RATE SCHEDULES?

A. Currently, APS has seven Residential rate schedules. Two of the rates are for special programs that APS actively supports and does not wish to change in any way. Rate E-3 provides discounts for qualifying low-income customers. Rate E-4 provides a discounted rate to customers who must use electricity for medical care equipment. We currently have three non time-of-use ("TOU") differentiated rates (E-10, E-12, and EC-1). Rates E-10 and EC-1 were frozen by the Commission in previous rate actions and have not been available to new customers for over 10 years. We also have two generally available TOU rates. Rate ET-1 is a time differentiated energy rate, while Rate ECT-1R is time differentiated and also includes a metered Demand charge.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED RESIDENTIAL RETAIL RATE SCHEDULES?

A. As I noted earlier, we are unbundling the Standard Offer rates to comply with the Competition Rules. Therefore, Rates E-12, ET-1, and ECT-1R will have discrete charges for each of the Revenue Cycle Services, a Generation charge, a Transmission charge, a Distribution charge, a Systems Benefits Charge, and the various surcharges I discuss in my testimony.

Q. WHAT ARE YOUR INTENTIONS FOR FROZEN RATE EC-1 AND ITS CUSTOMERS?

A. It is proposed that the frozen Rate EC-1 be eliminated. It is no longer available to new customers and produces a low rate of return that can be considered a burden to APS customers taking service on other rates. Rate EC-1 customers would be transferred to Rate ECT-1R unless they choose an alternative rate. Rate ECT-1R has been selected as the default rate as both rates have Demand components and many customers currently on Rate EC-1 are managing their demand through load controllers. These customers are aware of demand-based rates and the potential for saving money by actively managing their peak load. Rate ECT-1R also has a metered demand basis with the addition of a TOU element. Therefore, we believe that the transition from Rate EC-1 to Rate ECT-1R would provide the best continuity for the Rate EC-1 customers.

Q. WHAT ARE YOUR INTENTIONS FOR FROZEN RATE E-10 AND ITS CUSTOMERS?

A. It is proposed that frozen Rate E-10 be eliminated for the same basic reasons as stated above for Rate EC-1. However, for customers on Rate E-10, I am proposing a one-year phase-out period during which time APS would provide the E-10 customers with information on alternative rate options. Customers will, of course, be free to select any other Residential rate on which to take service. If a Rate E-10 customer does not select another rate option during the phase-out period, the default rate would be Rate E-12, since neither of those rates have time differentiated pricing or a Demand charge. I am also requesting that the current Rate E-10 be increased by 1.25 times the overall requested increase in this proceeding. This increase would be effective during the one-year phase-out period.

Q. ARE YOU PROPOSING CHANGES TO RATE ET-1?

A. Yes. In addition to unbundling the rate and increasing the charges to better recover costs, we are adding some features not currently found in the existing version of Rate ET-1. The first change is eliminating the TOU time periods during the winter season. In effect, all hours during the winter can be thought of as off-peak. When we examined hourly cost curves for the winter months, we found that the time period differentials were relatively small. Therefore, an on-peak price signal is not warranted. It should be noted that due to this winter change, most federal and state holidays will no longer have time-differentiated prices.

The second change proposed for Rate ET-1 is in response to research conducted by APS Customer Service that indicated customers would prefer some additional flexibility in the TOU rates. To accommodate that desire, we are proposing an experiment in which APS would offer customers optional time periods. The standard on-peak time period will continue to be 9AM to 9PM. Optional time periods are to be 7AM to 7PM and 8AM to 8PM. We propose that these optional time periods be initially limited to no more than 10,000 customers. In addition, the number of customers switching will be limited each year based on staff and meter availability.

Q. WOULD YOU EXPLAIN WHY YOU HAVE PLACED RESTRICTIONS ON PARTICIPATION IN THIS EXPERIMENT?

A. The experiment will require individually reprogramming each participating customer's meter. That will take time for APS personnel to accomplish and time away from other tasks such as installing new meters to meet customer growth, meter maintenance and replacement, etc.

Second, there should certainly be some revenue loss due to the fact that customers will pick the TOU period that minimizes their on-peak consumption. Although I cannot presently estimate this revenue attrition, it could be significant and it is not accounted for in our rate filing. Thus, I would hope to be able to get better information on the impact of this program on the Company and on other non-participating APS customers before we make it available to all comers.

Lastly, to the extent that current non-TOU customers would find the proposed "pick-a-period" TOU option attractive, it will require that we install TOU meters. By limiting the program to 10,000 customers while in the experimental stage, meter purchases and inventories can be better regulated.

Q. WOULD YOU DESCRIBE RATE ECT-1R, AS PROPOSED BY APS?

A. Yes, in addition to unbundling the rate and increasing the charges to better recover costs, Rate ECT-1R will continue to include time differentiated Energy charges and Demand charges in the Generation component. Currently, the on-peak time periods found in Rate ECT-1R are the same as found in Rate ET-1. Therefore, we propose the same TOU options be offered to Rate ECT-1R customers as will be offered to Rate ET-1 customers. Rate ECT-1R will also have no TOU differentiated energy component in the winter. It is intended that the 10,000 customer limit discussed with regard to the experimental "pick-a period" option be a total for both Rates ET-1 and ECT-1R taken together.

Q. ARE YOU PROPOSING CHANGES FOR RATE E-12?

A. Yes. In addition to increasing the rate level to bring it more in line with costs, the proposed rate has been simplified by eliminating one of the existing summer energy blocks.

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED RESIDENTIAL RATE CHANGES?

A. We are proposing the following:

- All rates have been reformatted and include adjustment clause charges and surcharges.
- Rates E-12, ET-1, and ECT-1R will be unbundled.
- Each Residential rate will be designed to improve cost tracking.
- Rate EC-1 will be eliminated.
- Rate E-10 will be eliminated, phased out over one year, and increased by 1.25 times the overall increase requested in this proceeding.

- Rate E-12 will be redesigned and further simplified.
- Time period options will be made available to customers on Rates ET-1 and ECT-1R on an experimental and limited basis.
- TOU periods will be eliminated during the winter season.
- The low income and medical equipment rates, Rates E-3 and E-4 respectively, will remain unchanged.

IX. GENERAL SERVICE RATE SCHEDULES

Q. WOULD YOU PLEASE DESCRIBE APS' GENERAL SERVICE RATE SCHEDULES?

A. APS has eleven General Service rate schedules. These are basically used for serving our commercial and industrial loads. There are five TOU schedules, one schedule for unmetered service, one schedule for athletic stadiums and arenas, a seasonal schedule, and one schedule for partial requirements service. There are two demand based, non-TOU differentiated schedules. Approximately 95% of our General Service customers are served on Rate E-32. Rate E-34 and TOU Rate E-35 are available for customers whose loads exceed three megawatts.

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED CHANGES IN THE GENERAL SERVICE SCHEDULES?

A. We propose to eliminate some frozen rate schedules, consolidate the TOU rates for customers under three megawatts, improve cost tracking and recovery, adjust rates with seasonal pricing differentials so that their summer and winter months correspond to those of our Residential rates, and unbundled the rate components.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED RATE E-32?

A. In addition to unbundling charges and improving cost recovery, we propose to modify the format of Rate E-32. The current schedule is complex and includes several billing blocks that are based on energy charges or load factor based charges. We propose to simplify the structure, and make it more understandable to our customers. The proposed schedule consists of two sections. The first section is designed for customers whose loads are 20 kW or less. Customers will be billed based on Energy charges without an explicit Demand charge. The second section is designed for customers whose loads are greater than 20 kW but less than 3,000 kW. Customers served under this section will be billed on the basis of metered Demand and Energy. The Demand and Energy components each have two billing blocks. The Demand charge has an initial rate block that ends at 500 kW. The Energy component has an initial block, which ends at 200 kWh/kW or a 27 percent load factor. In addition, discounts will now be available for customers taking service at Primary or Transmission voltage levels.

Q. WHY WERE BILLING BLOCKS INCLUDED IN THE PROPOSED RATE DESIGN?

A. The blocks were needed to reduce the effect on individual customers as we move from our existing Rate E-32 rate design to the more simplified design. In addition, the 20 kW point corresponds to the load level at which metering requirements change per the Competition Rules. Competitive customers with loads of greater than 20 kW are required to have interval data recorder meters, while the loads for customers of 20 kW or less can be load profiled, and therefore will not require such metering.

Q. HAVE YOU MODIFIED RATE E-32R?

A. Yes. Rate E-32R provides for partial requirements customers basically taking service under Rate E-32. The only changes proposed are to reflect the Demand component modifications proposed for Rate E-32. For customers under 20 kW, a contract demand will be established, as a measured demand may not be available.

Q. WOULD YOU PLEASE DESCRIBE THE CHANGES PROPOSED IN THE TOU RATE SCHEDULES FOR GENERAL SERVICE CUSTOMERS UNDER 3 MW?

A. As noted earlier in my testimony, we currently have a series of General Service TOU rates. Customer participation on Rates E-21, E-22, E-23, and E-24 is capped at a certain number of customers since these rates are experimental in nature. We have proposed that these experimental rates now be eliminated, and replaced with a new rate. Rate E-32TOU has been developed which will not be capped and will parallel and follow the same concepts as the proposed non-TOU Rate E-32. There is one section for customers 20 kW or less and one for customers over 20 kW.

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED CHANGES TO THE GENERAL SERVICE SCHEDULES?

A. Yes, the changes are as follows:

- All rates have been reformatted and include adjustment clause charges and surcharges.
- Rates with seasonal pricing differentials have been modified so that their summer and winter months correspond to those of our Residential rates.
- TOU Rates E-21, E-22, E-23, and E-24 will be eliminated and customers transferred to E-32 TOU.
- Rate E-30 for Unmetered Service will be increased to better reflect costs and the rate will be unbundled.
- Rate E-32 will be redesigned so that it will be unbundled and the rate design simplified. In addition, discounts will be available for customers who take service at Primary or Transmission voltage levels. The E-32R

rider has been modified to reflect the proposed change in Rate E-32.

- Rates E-34 and E-35 will be unbundled and the rates adjusted to allow for discounts for service taken at Primary and Transmission voltage levels, and to reflect the overall rate increase proposed in this rate case filing.
- Rate E-53 for service to Athletic Fields and Rate E-54 for Seasonal Service are used in conjunction with other applicable General Service rates and no stand alone changes to these rates are proposed.

X. CLASSIFIED SERVICE RATE SCHEDULES

Q. WOULD YOU PLEASE DESCRIBE WHAT IS MEANT BY "CLASSIFIED SERVICE?"

A. Classified Service provides for service to specific types of loads for which specific rate schedules are available. Examples of Classified Service include service to irrigation pumps and street lights.

Q. WOULD YOU PLEASE PROVIDE A GENERAL DESCRIPTION OF THE PROPOSED CHANGES TO THE CLASSIFIED SERVICE SCHEDULE?

A. Classified Service schedules tend to provide APS the lowest returns of all the rates in our electric tariff. For example, irrigation pumps generally operate at low load factors and during the summer months when the APS system peaks. Consequently, the Irrigation rates are not at a level that provide APS with what I would consider to be a reasonable rate of return. As I stated earlier in my testimony, we have proposed that the rate increase for each major customer class be limited to the overall average percentage increase that has been requested by APS. This limitation simply does not allow for a meaningful unbundling of rate schedules that vary greatly from following cost-of-service in their level or design. Therefore, we have not proposed that all Classified Service rates be unbundled. In addition, rates with seasonal pricing differentials have been modified so that their summer and winter months correspond to those of our Residential rates.

Q. WILL LIMITED UNBUNDLING PRESENT A BARRIER TO DIRECT ACCESS?

A. No. Customers who are currently served under a Classified Service rate schedule, such as Irrigation, can become a Direct Access customer by transferring to an applicable General Service schedule and obtaining Distribution services through the unbundled portion of the General Service rate.

Q. WOULD YOU PLEASE DESCRIBE THE SPECIFIC CHANGES PROPOSED FOR THE IRRIGATION SCHEDULES?

A. We currently have two basic Irrigation rates. Rate E-38 and its TOU companion E-38-8T have less than 160 customers. Rate E-221 and its TOU companion E-221-8T have approximately 1,400 Irrigation customers. We propose eliminating Rates E-38 and E-38-8T and transferring those customers to Rates E-221 or E-221-8T. Charges on Rate E-221 will be increased to meet our overall rate increase request along with some rate design modifications to make the rate more cost tracking. It is expected that some Irrigation class customers currently taking service on General Service Rate E-32 will transfer to Rate E-221 to take advantage of the effect the proposed design changes have on their particular loads.

Q. ARE YOU PROPOSING CHANGES TO THE STREET LIGHTING AND DUSK TO DAWN LIGHTING SCHEDULES?

A. Yes, in addition to improved cost tracking, we have reformatted Rate E-47 (Dusk to Dawn) and Rate E-58 (Street Lighting). Because customers on these rates often request different combinations of poles, arms, and fixtures, we have developed and proposed a menu format for these rates. Subject to certain physical/construction limitations, customers will be able to select the lighting system that best fits their needs. The menu system will also make it easier to add new poles or fixtures to the rate schedules, as they become available.

Q. HOW DID YOU RESTRUCTURE THE CHARGES WITHIN RATES E-47 AND E-58?

A. APS performed an extensive analysis of the costs of installing and maintaining each type of lighting equipment that we offer. This analysis resulted in recommended changes to the relationship between charges in the menu. The relative price of some fixtures increased while the relative price of other fixtures declined.

Q. DOES APS PROVIDE STREET LIGHTING SERVICE ON RATES OTHER THAN E-58?

A. Yes, Rate E-59 is used to provide energy service for government-owned street lighting systems. Under Rate E-59, APS has no responsibility for operations, maintenance, or replacement of street light poles or fixtures. There is also a series of "Share the Light" schedules for Street Lighting services in Litchfield Park, Ajo, Camp Verde, and other areas. The charges for these special schedules are found in Rate E-58.

Q. WHAT ARE THE PROPOSED CHANGES FOR THESE STREET LIGHTING RATES?

A. APS proposes to increase the overall charges under each of these rates at approximately the same level as our overall requested increase.

Q. ARE THERE ANY OTHER LIGHTING RELATED RATE SCHEDULES IN THE TARIFF?

A. Rate E-67 is used to provide energy service to the City of Phoenix for various non-Street Lighting systems. It is based on an old contract rate that has long expired. Because the level of this rate and its return is so substandard, I propose that it be increased by twice the average percent increase that APS is requesting in this rate case. This requested increase will still not bring the rate up to the average rate of return paid by our other retail customers.

Q. WOULD YOU PLEASE DESCRIBE ANY OTHER PROPOSED CHANGES FOR CLASSIFIED SERVICE CUSTOMERS?

A. Rate E-20 is used to provide TOU service to houses of worship. The pricing under this rate schedule is the same as the pricing under Rate E-21, which has been frozen since 1996, and has been eliminated in our rate proposal. We propose that Rate E-20 be frozen and therefore not available to new customers. New customers would take service on Rate E-32TOU or another General Service rate of their choice. Charges for customers who remain on Rate E-20 will be increased by one and one half times the overall requested increase in this proceeding.

We propose that charges under Rate E-40 for service to Agricultural Wind Machines and charges under frozen Rate E-51 for service to certain cogenerators and small power producers be increased by the same overall percentage as is being requested in this proceeding.

Partial Requirements Service Rates E-52 and E-55 currently have no customers being served on them and no increase is proposed at this time.

In addition, and as with our other rates, the Classified Service rate schedules will include provisions for the requested adjustment clause charges and surcharges.

XI. DIRECT ACCESS RATES

Q. WHAT WILL HAPPEN TO APS' EXISTING DIRECT ACCESS RATES?

A. Because we have functionally unbundled our applicable Standard Offer rates, the existing separate special Direct Access rates will no longer be necessary and, therefore, have been eliminated in our proposal. Customers seeking Direct Access service would purchase the required non-competitive services from APS as listed under the appropriate unbundled Standard Offer rate schedule. One or more ESPs would provide the needed competitive services. Currently, APS has no customers taking Direct Access service.

XII. "H" SCHEDULES

Q. WOULD YOU DESCRIBE THE "H" SCHEDULES BEING SPONSORED BY YOU?

A. The "H" Schedules are a series of summaries that present an analysis of the impacts of the proposed rates.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-1?

A. Schedule H-1 provides a summary of the revenue impact on each major customer classification, e.g. Residential, General Service, Irrigation, etc. This schedule compares the revenue generated under the proposed rates with the revenue generated under present rates.

To develop the data found in the column entitled "Present Rates," we began with actual revenue from the test year, but then made a series of normalization adjustments to that data. The adjustments were made to reflect normal weather, the year-end number of customers, the rate decreases that were effective in July of 2002 and 2003, and the removal of revenue associated with Franchise Fees included in current rate levels. The purpose of these adjustments was to enable us to compare existing and proposed rates on an "apples to apples" basis. For example, our current existing rates are based on costs that include approximately $29 million in Franchise Fee costs. We have proposed that, in the future, Franchise Fees will be treated like any other surcharged tax. If we did not remove the Franchise Fee costs from current rates levels, comparisons to the proposed rates would be less meaningful and very confusing.

Q. WOULD YOU DESCRIBE THE INFORMATION FOUND IN SCHEDULE H-2?

A. Schedule H-2 presents the information found in Schedule H-1 in a more detailed format. The comparisons of current and proposed revenue are shown by rate schedule whereas Schedule H-1 data is presented on a class basis. Schedule H-1 is actually a summary of the data found in Schedule H-2.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-3?

A. Schedule H-3 presents comparisons of the specifics of each rate schedule. These specifics include details such as the Basic Service Charge, billing blocks, Energy charges, and Demand charges. Although our proposed rates have been functionally unbundled, the information shown on Schedule H-3 is presented on a bundled basis to allow for easier comparisons to existing rate schedules. Additionally, in the proposed rates section, we have included a column that shows the proposed rates with the addition of a Franchise Fee element. The Franchise Fee element is based on the average Franchise Fee currently recovered in base rates. As I noted earlier in my testimony, we have included this information so that rate comparisons can be made on a common basis, with the knowledge that the Franchise Fee actually passed through to an individual customer will vary by municipality.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-4?

A. Schedule H-4 presents a typical bill comparison for our major rate schedules under existing and proposed rates. Bill comparisons are presented for varying levels of consumption and for seasons, when applicable. Schedule H-4 also includes additional columns of information so that complete comparisons can be made between existing and proposed rates. The additional columns show the Franchise Fees and the Competition Rules Compliance Charge ("CRCC"). These charges are added to the revenues determined by the rates so that a more complete "bill" can be computed. The "add-ons" of Sales Tax and Regulatory Assessment have not been included in the bill comparisons.

Q. WHAT IS THE CRCC?

A. In May of 2002, APS filed an amended application with the ACC requesting approval for a series of adjusters or surcharges including a PSA and the CRCC. The adjuster/surcharge request filing was made in accordance with the terms of the 1999 Settlement Agreement. The CRCC was developed to enable APS to recover the costs the Company incurred in order to comply with the Competition Rules. These costs are not recovered in current rates. However, since customers will see the CRCC charge on bills when APS' revised rates become effective, a column has been included on Schedule H-4 that demonstrates the impact of the CRCC on bills. The CRCC will be in effect for five years.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-5?

A. Schedule H-5 presents a series of bill frequency analyses for major rate schedules. This information includes the number of bills and energy consumed based on blocks of consumption levels. The data is presented for our Residential rate schedules. Data is not presented for the General Service schedules because the bill frequency data cannot be presented in a meaningful manner for customer classes in which customers are billed on both metered demand and energy.

XIII. <u>CONCLUSION</u>

Q. WOULD YOU STATE YOUR GENERAL CONCLUSIONS AS TO PRICING MATTERS IN THIS PROCEEDING?

A. The cost-of-service study has shown me that APS' current rates produce rates of return that vary greatly from each other and from the overall average and required rate of return. In addition, the rate designs stray greatly from the unit Demand, Energy, and Customer costs of providing service to our customers. The rates being proposed in this proceeding will meet APS' revenue requirement, better track costs, and have been simplified for better customer understanding and administration.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

Appendix A
Statement of Qualifications
Alan Propper

Alan Propper is Arizona Public Service Company's Director of Pricing. He is a veteran of the electric and gas utility industry with over 30 years of experience in utility company management and as an industry consultant. Mr. Propper holds the degrees of Mechanical Engineer from Stevens Institute of Technology and Master of Business Administration from San Francisco State University. The Arizona State Community College Certification Board has certified him as an Instructor of Engineering and Business Administration.

Mr. Propper's areas of expertise include pricing and rate design, embedded and marginal cost analyses, load research, load management programs, state and federal regulatory matters, contract negotiations between utilities concerning resale and wheeling services, contract negotiations between utilities and their major retail customers, and tariff administration. Mr. Propper has testified on numerous occasions on contract, pricing, and cost-of-service matters before many state and federal regulatory agencies.

Prior to rejoining APS after an eight year absence, Mr. Propper served as Regional Manager and Managing Executive Consultant for Resource Management International (now Navigant) and Principal Consultant and Director of Consulting Services for A&C Enercom. Prior to initially joining APS, Mr. Propper was employed as Supervisor of Rates for Consumers Power Company, Executive Consultant for Commonwealth Services, Forecast Engineer and Rate Engineer for Pacific Gas & Electric Company, and in Power Plant Operations for Public Service Electric & Gas Company.

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ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DEC. 31, 2002
($)

		<------ GJ ------>		
Line No.	Description	ELECTRIC TOTAL (1)	ACC JURISDICTION (2)	ALL OTHER (3)
	SUMMARY OF RESULTS			
1	DEVELOPMENT OF RATE BASE			
2	ELECTRIC PLANT IN SERVICE	$7,909,989,000	$7,637,477,656	$272,511,344
3	GENERAL & INTANGIBLE PLANT	$576,885,334	$565,827,594	$11,057,740
4	LESS: RESERVE FOR DEPRECIATION	($3,542,546,796)	($3,405,508,821)	($137,037,975)
5	OTHER DEFERRED CREDITS	($173,561,000)	($172,549,446)	($1,011,554)
6	WORKING CASH	$54,097,992	$52,979,748	$1,118,244
7	MATERIALS, SUPPLIES & PREPAYMENTS	$121,614,469	$119,442,953	$2,171,516
8	ACCUM. DEFERRED TAXES	($1,296,415,000)	($1,272,578,862)	($23,836,138)
9	REGULATORY ASSETS	$166,267,910	$165,564,194	$703,716
10	DECOMMISSIONING FUND	$194,440,466	$191,607,661	$2,832,805
11	GAIN FROM DISP. OF PLANT	($59,484,000)	($59,380,841)	($103,159)
12	MISCELLANEOUS DEFERRED DEBITS	$27,379,000	$26,958,959	$420,041
13	CUSTOMER ADVANCES	($45,512,876)	($45,512,876)	$0
14	CUSTOMER DEPOSITS	($39,865,000)	($39,865,000)	$0
15	PROFORMA ADJUSTMENTS	$327,729,500	$443,013,080	($115,283,580)
16	TOTAL RATE BASE	$4,221,018,999	$4,207,475,999	$13,543,000
17				
18	DEVELOPMENT OF RETURN			
19	REVENUES FROM RATES	$1,874,801,594	$1,839,197,107	$35,604,487
20	PROFORMA TO REVENUES FROM RATES	($47,613,375)	($47,613,375)	$0
21	OTHER ELECTRIC REVENUE	$150,987,521	$148,562,410	$2,425,111
22	TOTAL OPERATING REVENUES	$1,978,175,740	$1,940,146,142	$38,029,598
23				
24	OPERATING EXPENSES			
25	OPERATION & MAINTENANCE	$1,014,770,483	$998,176,929	$16,593,554
26	ADMINISTRATIVE & GENERAL	$109,788,347	$108,572,720	$1,215,627
27	DEPRECIATION & AMORT EXPENSE	$273,216,517	$266,778,129	$6,438,388
28	AMORTIZATION ON GAIN	($4,708,735)	($4,698,862)	($9,873)
29	REGULATORY ASSETS	$114,979,666	$114,979,666	$0
30	PROFORMA ADJUSTMENTS	($4,875,035)	($13,023,229)	$8,148,194
31	TAXES OTHER THAN INCOME	$123,391,838	$119,346,144	$4,045,694
32	INCOME TAX	$86,607,563	$86,144,085	$463,478
33	TOTAL OPERATING EXPENSES	$1,713,170,644	$1,676,275,581	$36,895,063
34				
35	OPERATING INCOME	$265,005,096	$263,870,561	$1,134,535
36				
37	RETURN	$265,005,096	$263,870,561	$1,134,535
38				
39	RATE OF RETURN (PRESENT)	6.28%	6.27%	8.38%
40				
41	INDEX RATE OF RETURN (PRESENT)	1.00	1.00	1.33

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DEC. 31, 2002
($)

		<---- GE-1					---->
Line No.	Description	TOTAL RETAIL (4)	RESIDENTIAL (5)	GENERAL SERVICE (6)	IRRIGATION (7)	STREET LIGHTING (8)	DUSK TO DAWN (9)
	SUMMARY OF RESULTS						
1	**DEVELOPMENT OF RATE BASE**						
2	ELECTRIC PLANT IN SERVICE	$7,637,477,656	$4,232,372,444	$3,291,758,562	$12,488,353	$70,515,364	$30,342,932
3	GENERAL & INTANGIBLE PLANT	$565,827,594	$342,186,241	$214,880,479	$840,639	$5,179,407	$2,740,828
4	LESS: RESERVE FOR DEPRECIATION	($3,405,508,821)	($1,852,081,097)	($1,514,197,687)	($5,423,455)	($23,515,621)	($10,290,960)
5	OTHER DEFERRED CREDITS	($172,549,446)	($93,339,740)	($78,240,066)	($272,530)	($457,389)	($239,721)
6	WORKING CASH	$52,979,748	$29,244,091	$22,993,439	$80,589	$452,725	$208,904
7	MATERIALS, SUPPLIES & PREPAYMENTS	$119,442,953	$62,245,085	$55,895,336	$188,712	$782,591	$331,228
8	ACCUM. DEFERRED TAXES	($1,272,578,862)	($689,516,808)	($569,702,479)	($2,084,756)	($7,890,379)	($3,384,439)
9	REGULATORY ASSETS	$165,564,194	$82,742,988	$82,279,646	$256,569	$207,897	$77,094
10	DECOMMISSIONING FUND	$191,607,661	$86,668,985	$103,484,099	$260,707	$870,910	$322,960
11	GAIN FROM DISP. OF PLANT	($59,380,841)	($30,751,661)	($28,532,875)	($96,305)	$0	$0
12	MISCELLANEOUS DEFERRED DEBITS	$26,958,959	$16,306,046	$10,235,120	$40,124	$246,948	$130,722
13	CUSTOMER ADVANCES	($45,512,876)	($29,881,809)	($12,797,831)	($2,373,090)	($460,146)	$0
14	CUSTOMER DEPOSITS	($39,865,000)	($18,337,900)	($21,081,530)	($52,324)	($267,833)	($125,412)
15	PROFORMA ADJUSTMENTS	$443,013,080	$229,255,123	$213,024,093	$717,815	$11,708	$4,342
16	**TOTAL RATE BASE**	**$4,207,475,999**	**$2,367,111,987**	**$1,769,998,307**	**$4,571,046**	**$45,676,181**	**$20,118,478**
17							
18	**DEVELOPMENT OF RETURN**						
19	REVENUES FROM RATES	$1,839,197,107	$911,780,435	$908,197,108	$2,257,000	$11,567,156	$5,395,408
20	PROFORMA TO REVENUES FROM RATES	($47,613,375)	($21,882,852)	($24,601,762)	($157,808)	($773,504)	($197,449)
21	OTHER ELECTRIC REVENUE	$148,562,410	$71,186,642	$74,249,338	$214,786	$2,582,662	$328,981
22	**TOTAL OPERATING REVENUES**	**$1,940,146,142**	**$961,084,225**	**$957,844,684**	**$2,313,978**	**$13,376,314**	**$5,526,940**
23							
24	**OPERATING EXPENSES**						
25	OPERATION & MAINTENANCE	$998,176,929	$504,207,958	$482,891,907	$1,450,345	$7,185,387	$2,441,332
26	ADMINISTRATIVE & GENERAL	$108,572,720	$65,579,950	$40,778,896	$167,469	$1,382,051	$664,353
27	DEPRECIATION & AMORT EXPENSE	$266,778,129	$151,202,510	$111,026,243	$431,240	$2,856,588	$1,261,548
28	AMORTIZATION ON GAIN	($4,698,862)	($2,424,816)	($2,265,642)	($7,586)	($596)	($221)
29	REGULATORY ASSETS	$114,979,666	$59,544,722	$55,248,467	$186,476	$0	$0
30	PROFORMA ADJUSTMENTS	($13,023,229)	($6,902,815)	($5,682,301)	($62,178)	($324,438)	($51,498)
31	TAXES OTHER THAN INCOME	$119,346,144	$68,525,934	$48,688,043	$193,761	$1,339,525	$598,881
32	INCOME TAX	$86,144,085	$18,615,690	$67,805,516	($74,606)	($195,292)	($7,223)
33	**TOTAL OPERATING EXPENSES**	**$1,676,275,581**	**$858,349,133**	**$798,491,130**	**$2,284,920**	**$12,243,225**	**$4,907,174**
34							
35	**OPERATING INCOME**	**$263,870,561**	**$102,735,092**	**$159,353,555**	**$29,058**	**$1,133,090**	**$619,767**
36							
37	**RETURN**	**$263,870,561**	**$102,735,092**	**$159,353,555**	**$29,058**	**$1,133,090**	**$619,767**
38							
39	**RATE OF RETURN (PRESENT)**	**6.27%**	**4.34%**	**9.00%**	**0.64%**	**2.48%**	**3.08%**
40							
41	**INDEX RATE OF RETURN (PRESENT)**	**1.00**	**0.69**	**1.43**	**0.10**	**0.40**	**0.49**

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DEC. 31, 2002
($)

Line No.	Description	<---- GE-2 ---- TOTAL GENERAL SVC (10)	SMALL GEN. SERVICE (11)	MEDIUM GEN. SERVICE (12)	LARGE GEN. SERVICE (13)	EXTRA-LARGE GEN. SERVICE (14) ---->
	SUMMARY OF RESULTS					
1	DEVELOPMENT OF RATE BASE					
2	ELECTRIC PLANT IN SERVICE	$3,291,758,562	$1,206,095,683	$1,336,430,292	$357,971,573	$391,261,013
3	GENERAL & INTANGIBLE PLANT	$214,880,479	$85,681,122	$78,785,796	$22,551,051	$27,862,510
4	LESS: RESERVE FOR DEPRECIATION	($1,514,197,687)	($538,474,987)	($609,735,998)	($169,515,642)	($196,471,061)
5	OTHER DEFERRED CREDITS	($78,240,066)	($27,450,487)	($31,003,705)	($8,928,400)	($10,857,474)
6	WORKING CASH	$22,993,439	$8,168,419	$8,985,687	$2,601,327	$3,238,006
7	MATERIALS, SUPPLIES & PREPAYMENTS	$55,895,336	$18,691,977	$22,419,236	$6,552,777	$8,231,346
8	ACCUM. DEFERRED TAXES	($569,702,479)	($202,880,381)	($231,433,493)	($63,513,382)	($71,875,223)
9	REGULATORY ASSETS	$82,279,646	$26,402,002	$33,114,365	$9,944,051	$12,819,228
10	DECOMMISSIONING FUND	$103,484,099	$29,107,580	$40,867,606	$13,561,603	$19,947,311
11	GAIN FROM DISP. OF PLANT	($28,532,875)	($9,640,509)	($11,575,733)	($3,323,605)	($3,993,028)
12	MISCELLANEOUS DEFERRED DEBITS	$10,235,120	$4,081,828	$3,751,032	$1,074,160	$1,328,100
13	CUSTOMER ADVANCES	($12,797,831)	($4,729,974)	($5,077,344)	($1,212,923)	($1,777,590)
14	CUSTOMER DEPOSITS	($21,081,530)	($7,814,202)	($8,349,369)	($1,993,379)	($2,924,582)
15	PROFORMA ADJUSTMENTS	$213,024,093	$71,896,508	$86,408,468	$24,834,029	$29,885,088
16	TOTAL RATE BASE	$1,769,998,307	$659,134,580	$713,586,840	$190,603,241	$206,673,646
17						
18	DEVELOPMENT OF RETURN					
19	REVENUES FROM RATES	$908,197,108	$335,662,237	$360,313,341	$86,074,979	$126,146,551
20	PROFORMA TO REVENUES FROM RATES	($24,601,762)	($7,796,931)	($13,741,145)	($3,835,236)	$771,550
21	OTHER ELECTRIC REVENUE	$74,249,338	$22,605,331	$29,539,363	$9,282,155	$12,822,490
22	TOTAL OPERATING REVENUES	$957,844,684	$350,470,637	$376,111,559	$91,521,898	$139,740,591
23						
24	OPERATING EXPENSES					
25	OPERATION & MAINTENANCE	$482,891,907	$151,015,727	$187,851,693	$59,804,779	$84,219,709
26	ADMINISTRATIVE & GENERAL	$40,778,896	$16,459,677	$15,411,629	$4,167,768	$4,739,821
27	DEPRECIATION & AMORT EXPENSE	$111,026,243	$41,705,361	$44,549,096	$11,864,335	$12,907,452
28	AMORTIZATION ON GAIN	($2,265,642)	($761,494)	($918,404)	($264,941)	($320,804)
29	REGULATORY ASSETS	$55,248,467	$18,667,006	$22,414,197	$6,435,527	$7,731,736
30	PROFORMA ADJUSTMENTS	($5,682,301)	$1,063,327	($2,767,102)	($2,037,870)	($1,940,656)
31	TAXES OTHER THAN INCOME	$48,688,043	$18,595,321	$19,428,372	$5,135,385	$5,528,965
32	INCOME TAX	$67,805,516	$32,807,944	$26,767,990	$173,964	$8,055,619
33	TOTAL OPERATING EXPENSES	$798,491,130	$279,552,869	$312,737,471	$85,278,948	$120,921,841
34						
35	OPERATING INCOME	$159,353,555	$70,917,768	$63,374,088	$6,242,949	$18,818,749
36						
37	RETURN	$159,353,555	$70,917,768	$63,374,088	$6,242,949	$18,818,749
38						
39	RATE OF RETURN (PRESENT)	9.00%	10.76%	8.88%	3.28%	9.11%
40						
41	INDEX RATE OF RETURN (PRESENT)	1.43	1.71	1.41	0.52	1.45

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DEC. 31, 2002
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		<------------------------------ GE-3 ------------------------------>					
Line No.	Description	TOTAL RESIDENTIAL (15)	RESIDENTIAL E-10 (16)	RESIDENTIAL E-12 (17)	RESIDENTIAL EC-1 (18)	RESIDENTIAL ET-1 (20)	RESIDENTIAL ECT-1 (21)
	SUMMARY OF RESULTS						
1	DEVELOPMENT OF RATE BASE						
2	ELECTRIC PLANT IN SERVICE	$4,232,372,444	$384,083,652	$1,301,283,148	$206,561,469	$1,937,185,658	$403,258,518
3	GENERAL & INTANGIBLE PLANT	$342,186,241	$32,811,770	$119,614,373	$15,343,639	$145,648,731	$28,767,728
4	LESS: RESERVE FOR DEPRECIATION	($1,852,081,097)	($167,811,378)	($568,016,302)	($92,392,271)	($845,927,724)	($177,933,423)
5	OTHER DEFERRED CREDITS	($93,339,740)	($8,458,699)	($28,823,032)	($4,748,685)	($42,483,627)	($8,825,697)
6	WORKING CASH	$29,244,091	$2,715,983	$9,448,160	$1,417,157	$12,910,392	$2,752,398
7	MATERIALS, SUPPLIES & PREPAYMENTS	$62,245,085	$5,645,569	$18,971,646	$3,190,088	$28,194,883	$6,242,900
8	ACCUM. DEFERRED TAXES	($689,516,808)	($61,978,706)	($207,928,101)	($34,700,768)	($318,332,612)	($66,576,621)
9	REGULATORY ASSETS	$82,742,988	$7,352,549	$24,185,230	$4,494,768	$38,195,531	$8,514,910
10	DECOMMISSIONING FUND	$86,668,985	$7,884,417	$25,935,286	$4,908,048	$37,999,671	$9,941,563
11	GAIN FROM DISP. OF PLANT	($30,751,661)	($2,710,947)	($8,917,233)	($1,646,832)	($14,433,034)	($3,043,616)
12	MISCELLANEOUS DEFERRED DEBITS	$16,306,046	$1,563,665	$5,701,497	$731,108	$6,939,454	$1,370,322
13	CUSTOMER ADVANCES	($29,881,809)	($2,811,117)	($10,069,381)	($1,514,183)	($12,589,041)	($2,898,088)
14	CUSTOMER DEPOSITS	($18,337,900)	($1,725,129)	($6,179,388)	($929,225)	($7,725,656)	($1,778,502)
15	PROFORMA ADJUSTMENTS	$229,255,123	$20,213,520	$66,489,202	$12,280,799	$107,562,969	$22,708,633
16	TOTAL RATE BASE	$2,367,111,987	$216,775,149	$741,695,106	$112,995,111	$1,073,145,595	$222,501,026
17							
18	DEVELOPMENT OF RETURN						
19	REVENUES FROM RATES	$911,780,435	$85,775,314	$307,245,930	$46,202,107	$384,128,045	$88,429,039
20	PROFORMA TO REVENUES FROM RATES	($21,882,852)	($6,853,175)	($5,812,496)	($3,449,426)	($3,015,166)	($2,752,589)
21	OTHER ELECTRIC REVENUE	$71,186,642	$6,468,618	$21,508,908	$3,833,679	$31,726,327	$7,649,111
22	TOTAL OPERATING REVENUES	$961,084,225	$85,390,757	$322,942,342	$46,586,360	$412,839,206	$93,325,561
23							
24	OPERATING EXPENSES						
25	OPERATION & MAINTENANCE	$504,207,958	$46,962,540	$161,169,522	$26,074,132	$218,635,643	$51,366,120
26	ADMINISTRATIVE & GENERAL	$65,579,950	$6,246,711	$22,502,502	$2,913,077	$28,271,323	$5,646,338
27	DEPRECIATION & AMORT EXPENSE	$151,202,510	$13,889,320	$47,790,119	$7,188,772	$68,254,263	$14,080,036
28	AMORTIZATION ON GAIN	($2,424,816)	($213,929)	($703,687)	($130,038)	($1,136,235)	($240,927)
29	REGULATORY ASSETS	$59,544,722	$5,249,231	$17,266,519	$3,188,776	$27,946,816	$5,893,381
30	PROFORMA ADJUSTMENTS	($6,902,815)	($356,027)	$573,752	($520,659)	($5,352,249)	($1,247,632)
31	TAXES OTHER THAN INCOME	$68,525,934	$6,326,819	$21,917,460	$3,215,890	$30,770,315	$6,295,451
32	INCOME TAX	$18,615,690	$193,138	$11,522,065	$439,781	$4,661,039	$1,799,667
33	TOTAL OPERATING EXPENSES	$858,349,133	$78,297,802	$282,038,252	$42,369,732	$372,050,914	$83,592,434
34							
35	OPERATING INCOME	$102,735,092	$7,092,955	$40,904,090	$4,216,629	$40,788,292	$9,733,127
36							
37	RETURN	$102,735,092	$7,092,955	$40,904,090	$4,216,629	$40,788,292	$9,733,127
38							
39	RATE OF RETURN (PRESENT)	4.34%	3.27%	5.51%	3.73%	3.80%	4.37%
40							
41	INDEX RATE OF RETURN (PRESENT)	0.69	0.52	0.88	0.59	0.61	0.70

EXHIBIT
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APS-11
admitted

DIRECT TESTIMONY OF DAVID J. RUMOLO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-___

June 27, 2003

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TESTIMONY OF DAVID J. RUMOLO
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-____)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. David J. Rumolo, 400 North Fifth Street, Phoenix Arizona, 85004

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Manager of State Pricing for Arizona Public Service Company ("APS" or "Company"). A summary of my qualifications and experience is attached to this testimony as Appendix A.

Q. WOULD YOU PLEASE DESCRIBE THE FUNCTIONS OF THE COMPANY'S STATE PRICING GROUP?

A. The State Pricing Group is part of the APS Pricing and Regulation Department. The Group is responsible for all retail pricing-related activities including rate development, service policy development, and development of material for filings with the Arizona Corporation Commission ("Commission").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe the proposed changes to APS' service schedules that address policies pertaining to providing retail electric service to customers. These service schedules include both general terms and conditions of service and specific policies on topics such as line extensions, meter testing, direct access requirements, and specialized metering.

II. SUMMARY OF TESTIMONY

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. My testimony addresses proposed changes to the APS service schedules on file with the Commission. APS is proposing revisions to Schedule 1 that will impact current revenue. All the other changes to the service schedules will have no revenue impact. However, the Company is also proposing changes in Schedule 3 that may impact the contributions to capital that customers and developers make when requesting new services that require line extensions.

Q. WHY ARE YOU PROPOSING REVISIONS TO THE SERVICE SCHEDULES?

A. Because APS is revising its retail rate schedules in this rate case, we determined that this would also be an appropriate time to examine all of the aspects of our retail tariff. Many of the service schedules have not been reviewed in years. Thus, the Company examined them in the context of current electric utility trends and practices and to allow the Company to charge cost-based fees for special services to customers requiring the services. This ensures that the entire customer base is not paying for costs caused only by a few customers

Q. WHAT PROCESSES WERE USED TO REVIEW THE SERVICE SCHEDULES?

A. We formed working groups comprised of employees who are involved in the implementation and administration of the schedules. These are the "hands-on" personnel who deal with the service schedules on a daily basis. They were asked to review the schedules and propose appropriate changes.

Q. IN GENERAL, WHAT IS THE NATURE OF THE PROPOSED CHANGES?

A. Many of the changes are simply editorial in nature. For example, some service schedules had inconsistent or potentially confusing formatting. Thus, in some service schedules, without defining either term, APS was referred to as "Company" in some places and as "APS" in other places. We have reformatted the schedules to address these inconsistencies. We also reviewed current charges or instituted new charges to ensure that the service schedules adequately reflect the costs for customer-requested activities. I will explain each of these charges later in this testimony. Each service schedule for which APS is proposing changes is attached to my testimony as Appendix B. In the set of service schedules provided in Appendix B, the proposed changes from the current schedules are shown in redline format.

III. SCHEDULE 1 - GENERAL TERMS AND CONDITIONS

Q. PLEASE DESCRIBE THE PROPOSED CHANGES IN SCHEDULE 1 THAT IMPACT APS' REVENUE.

A. Schedule 1 lists the terms and conditions for service. I will highlight some of the more significant changes that are proposed. First, APS is proposing that the Company be allowed to assess a "trip charge" to customers when appropriate. For example, a trip charge would be assessed when a service technician travels to a customer's premise to complete a customer-requested service, but is unable to complete the service because of lack of meter access. Also, APS proposes to increase the "after hours" charge to reflect current costs for meter reading, installation or turn on service and is requesting the ability to charge the customer an hourly rate for other after-hours or holiday work.

Q. WHY ARE THESE CHANGES BEING REQUESTED?

A. These changes are being proposed so that APS can better address cost causation and charge customers appropriately. For example, if a service call is requested for after-hours work to better accommodate a customer's specific request, it is appropriate for that customer to bear the additional cost of that special service. Otherwise, in the long run, all customers may pay for the costs of special service requested by a few customers.

Q. WILL ANY OF THE PROPOSED CHANGES IN SCHEDULE 1 RESULT IN HIGHER CHARGES TO CUSTOMERS?

A. Yes, some customers may see higher charges. However, any such higher changes are limited to "optional" services and are entirely within a customer's control. I have tabulated the old and new charges below:

DESCRIPTION (SCHEDULE 1 SECTION)	CURRENT CHARGE	PROPOSED CHARGE
Trip charge (2.2.1)	None	$17.50
Outside of normal business hours – Meter read, install or turn on service (2.2.2)	$50.00	$75.00
Outside of normal business hours – other services (2.2.3)		Hourly cost
Reconnection at pole (4.5.1)	$87.50	$100.00
On site energy evaluation (4.6)	$50.00	$90.00
Joint site visit (6.2.3)	$30.00 metro $75.00 outside $30/hr after 30 minutes	$70.00 (min.) in all areas, Actual hourly cost after 30 minutes
Meter test (6.5)	$25.00	$30.00 in shop $100.00 in field

Q. ARE YOU REQUESTING ANY OTHER CHANGES IN SCHEDULE 1 THAT IMPACT THE REVENUE OF APS?

A. Yes, APS is requesting approval to provide an electronic rather than paper bill to a customer upon the customer's request. In addition to the fact that some customers simply prefer to receive electronic bills, elimination of the paper bill will provide savings to APS by reducing postage and printing costs. Thus, to encourage customers to opt for an electronic bill in lieu of a paper bill, APS will provide a one time $5.00 incentive. A customer may switch back to the paper bill option without penalty. However, each customer will be entitled to only one $5.00 incentive.

Q. PLEASE DESCRIBE THE NON- REVENUE SCHEDULE 1 CHANGES.

A. APS is proposing that the process for establishing residential customer creditworthiness be modified. In the past, other utilities would provide customers with a letter that described the creditworthiness of a customer. APS would accept such a letter and, if appropriate, would waive security deposits. Today, however, many utilities have discontinued the practice of providing creditworthiness letters. In lieu of the letter, APS began the practice of requesting a report from credit rating agencies like virtually all other businesses do and using that information to determine whether a security deposit was needed. The proposed change affirms this current industry practice.

Q. WHAT OTHER CHANGES HAVE YOU PROPOSED FOR SCHEDULE 1.

A. One of the ongoing issues that our field personnel face today is difficulty with meter access. Inaccessible meters cause several problems. From the customer's perspective, lack of meter access may limit rate choice. Some of our retail schedules require that meters be reset after each monthly read. Without monthly access, these rate options become unavailable to the customer. It also prevents APS from providing monthly billings that are based on actual meter readings rather than estimates. From APS' perspective, the Company needs unassisted access to meters for maintenance, testing, and other purposes. To enforce the meter access requirements, APS is requesting the right to terminate service to a customer if after six months of good faith efforts to resolve access issues access remains restricted. The change also allows APS to offer, at the customer's expense, a remotely read meter option for those customers who cannot provide unassisted access.

Q. ARE YOU REQUESTING ANY OTHER CHANGES IN SCHEDULE 1 THAT PERTAIN TO METERING AND METER READING?

A. Yes. APS is also proposing to clarify language regarding power factor requirements to better describe the requirements and potential remedies for the Company if power factor requirements are not met.

IV. <u>SCHEDULE 3 - LINE EXTENSIONS</u>

Q. WHAT IS SCHEDULE 3?

A. Schedule 3 is APS' line extension policy. The current policy includes three main elements that define conditions governing line extensions. These elements are: (1) a footage allowance for residential extensions, (2) a revenue test for extensions when the construction cost is under $25,000, and (3) an economic feasibility analysis for extensions when the cost exceeds $25,000 or that are not subject to the footage allowance or revenue test. Also, when I refer to "residential" customers, I mean individual residential premises as opposed to subdivision developers. Line extensions for residential subdivisions being constructed by developers are evaluated under the revenue test or an economic feasibility analysis.

Q. PLEASE DESCRIBE THE CHANGES THAT ARE PROPOSED IN THE POLICY.

A. The current line extension policy is based on one that originated in 1954. Under the footage allowance portion of the current extension policy, permanent residential customers are provided with a 1,000-feet free construction allowance. If the customer's extension exceeds 1,000 feet but is less than 2,000 feet or the construction cost exceeds $25,000, the policy requires that the customer sign an extension agreement and provide a refundable advance. Under our proposed new policy, the footage basis is eliminated and permanent residential customers will be given a dollar-based equipment allowance. If the construction cost of the extension exceeds the allowance, the customer will be required to make a non-refundable contribution in aid of construction. This change only applies to permanent residential extensions where the construction cost is under $25,000. Line extensions where the cost is over $25,000 will be evaluated under an economic feasibility analysis discussed below, as applicable.

Q. HOW DOES THE CURRENT APS POLICY COMPARE WITH INDUSTRY TRENDS?

A. I am currently the Vice-Chairman of the Edison Electric Institute's Economic Regulation and Competition Committee and the topic of line extension policies is an agenda item at almost every semi-annual meeting. We have extensive discussions regarding the application and administration of line extension policies and, almost universally, utility companies struggle with developing policies that are fair to new customers, existing customers and the companies. Tracking extension contracts and administering extension policies are difficult issues that most utilities face. Utilities are moving from footage-based policies to construction-allowance based policies in order to improve extension policy administration and more correctly recover costs. The construction allowance approach recognizes that construction costs for individual customer locations can vary widely. APS believes that our proposed change is more equitable and is consistent with the current trends in the industry.

Q. ARE THERE OTHER REASONS SUPPORTING A CHANGE TO AN CONSTRUCTION ALLOWANCE?

A. The primary reason to convert to a construction allowance approach is to recognize that construction costs can vary significantly for each individual extension. The Company's service territory is very diverse. There are densely populated areas, rural areas, desert areas and mountainous areas. Because of this diversity and also to recognize that some extensions are overhead while others are underground, an allowance based on a fixed investment amount is fairer. Under a footage allowance-based approach, the cost of a short, very expensive extension results in an unfair burden on the rest of the Company's customers.

Q. WHAT IS THE PROPOSED CONSTRUCTION ALLOWANCE UNDER APS' REVISED LINE EXTENSION POLICY?

A. APS is proposing a residential extension allowance of $3,500 per permanent residential customer.

Q. HOW WAS THIS AMOUNT DETERMINED?

A. APS examined several approaches. In other states that have adopted the construction allowance approach, the allowance is based on the average net embedded distribution investment per customer based on a cost of service study. The underlying theory is that this average is the investment on which retail rates are designed. For APS, the average net embedded investment, excluding substation plant investment, for residential customers is approximately $1,500. We also analyzed the average plant investment from a reproduction cost basis and determined that value to be approximately $2,600. We elected to apply a more generous $3,500 allowance for several reasons. First, this allowance equates to the cost of a typical 500-feet underground extension, which is comparable to the allowance provided by other Arizona utilities. Second, we wanted to ease the transition from the current 1000-feet allowance. Today, the construction costs for a 1000-feet overhead extension is approximately $10,000. Thus, simply converting the existing footage allowance to an equivalent construction allowance would not solve the problem of excessive investment needed to serve one customer and would not accurately capture average embedded costs. However, because APS will no longer provide construction advance refunds for residential extensions under $25,000, the proposed allowance will ease the transition to the new method.

Q. HOW WILL THE EXTENSION POLICY BE APPLIED TO NON-RESIDENTIAL APPLICATIONS?

A. We will continue to use a revenue test for non-residential extensions where the construction cost does not exceed $25,000 and an economic feasibility based analysis for extensions when the cost exceeds $25,000. The revenue test is based on a simple relationship between expected revenue from a customer and the extension cost. Currently, if two times the customer's expected annual revenue is more than the cost of the extension less nonrefundable contributions, the extension is provided for free. If expected revenue does not meet the revenue test, an advance is received from the customer. The economic feasibility-based analysis is a more exhaustive approach that entails examining the return on investment for a particular extension.

Q. DOES APS PROPOSE TO CHANGE THE METHODOLOGIES USED TO COMPUTE THE REVENUE BASIS TEST OR THE ECONOMIC FEASIBILITY TEST?

A. Yes. Historically, the tests were based on total expected bundled-rate sales revenue from an individual customer in case of a single customer or customers in a subdivision. In the future, APS will perform the analysis based on the revenue generated by the distribution component of retail rates. Thus, the economic analysis will make no distinction between Standard Offer customers and Direct Access customers. With this change, the multiplier for the revenue test will be six. In other words, the extension will be free if six times the annual distribution revenue received from the extension is equal to or greater than the extension cost.

Q. ARE YOU PROPOSING ANY OTHER CHANGES TO THE ECONOMIC FEASIBILITY REQUIREMENTS?

A. Yes, current policy allows APS to assess a facilities charge in cases where an extension is not economically feasible even after we receive an advance. Currently, the facilities charge is collected on an annual basis until such time as the extension becomes economically feasible without the facilities charge. The majority of facilities charge agreements are needed for no more than a few years. The few agreements that continue for longer periods return little revenue and are difficult to administer. Thus, APS is proposing two customer options. The customer may elect to pay the facilities charge for a five-year period or make a one time payment based on the present worth of the five-year facilities charge income stream. The facilities charge would be reduced, eliminated, or refunded if the economics of the extension improve. These modifications reflect a change in practice in administering the extension policy but do not require changes to the policy language.

Q. IS APS PROPOSING TO MAKE ANY CHANGES TO THE METHODOLOGY USED TO DETERMINE THE ECONOMIC FEASIBILITY OF REAL ESTATE DEVELOPMENTS?

A. Yes, in addition to using only distribution revenue and expenses in the economic feasibility analysis, APS is changing the methodology used to estimate sales volume. Currently, the analysis assumes that all residential customers in a development are all-electric. This is no longer a valid assumption. For example, in most new residential developments natural gas is available and most new homes are dual-fuel. In the Company's new model, APS will run the economic analysis under a dual-fuel or all-electric basis, depending on the specifics of the development. If the developer offers natural gas appliances, we will use the dual-fuel option. We will use the all-electric option only if natural gas is unavailable. The economic analysis for commercial customers is presently performed based on expected electrical load so there will be no change in the analysis for commercial customers.

Q. ARE THERE ANY OTHER CHANGES PROPOSED FOR THE LINE EXTENSION POLICY?

A. Yes, we have made several editorial changes to the schedule. APS is also proposing to eliminate some language regarding line extensions to irrigation customers. The current version of Schedule 3 includes refund and advance provisions that are unique to irrigation customers. All future non-agricultural irrigation extensions will be handled under the revenue test or economic feasibility analyses discussed earlier. Agricultural irrigation extensions will be funded through customer advances that are subject to refund. Also, APS is proposing to eliminate language that was specific to customers served on the network distribution systems such as the network that exists in downtown Phoenix and to add language that provides for a customer contribution when the customer requests an additional primary feeder. This would be applicable to customers who have a high reliability requirement and request special service. Finally, language has been added to allow customers to design and construct facilities that would otherwise be designed and constructed by APS. This provides customers with the option of providing facilities to APS in lieu of providing construction advances for APS construction. Any facilities designed and constructed by customers must be in accordance with APS specifications and will be inspected by APS.

V. <u>SCHEDULE 4 – TOTALIZING</u>

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO SCHEDULE 4.

A. Schedule 4 addresses policies relative to totalizing of meter readings. It is applied when customers at a single premise receive service through multiple service entrances. Historically, totalizing has only been applicable to general service customers with three-phase service. Recently, however, APS has had a few instances where totalizing could be applicable to residential customers. The proposed changes merely make that option available to residential customers and single-phase commercial customers. APS is also proposing language to address the possibility that a customer with meters that are totalized may request that the meters no longer be totalized. This possibility is not addressed in the current version of Schedule 4. We are also removing the current prohibition on same-site remote totalizing.

VI. SCHEDULE 7 – METER PERFORMANCE MONITORING PLAN

Q. PLEASE DESCRIBE THE PROPOSED CHANGES IN SCHEDULE 7.

A. The proposed changes to the Company's Meter Performance Monitoring Plan service schedule consist of editorial changes to reflect current American National Standards Institute ("ANSI") standards. The proposed changes also add language for performance monitoring of solid-state meters.

VII. SCHEDULE 10 – TERMS AND CONDITIONS FOR DIRECT ACCESS

Q. PLEASE DESCRIBE THE PROPOSED CHANGES FOR SCHEDULE 10

A. This is the first revision of Schedule 10 since it became effective in 1998. The proposed changes are largely editorial. For example, all references to "APS" have been changed to "Company" to be consistent with the other service schedules. Also, we eliminated language that addressed the phase-in of competition, as that language is no longer necessary. None of the proposed changes impact the ability of Energy Service Providers or Direct Access customers to opt for competitive choice in APS' service territory.

VIII. SCHEDULE 15 – SPECIALIZED METERING

Q. PLEASE DESCRIBE THE PROPOSED CHANGES IN SCHEDULE 15

A. Schedule 15 was titled "Conditions Governing the Providing of Electric KWH Pulses." APS is proposing to change the title to "Conditions Governing the Provision of Specialized Metering" to reflect changes that broaden the scope of the schedule. A wider scope is needed to reflect the state of the art of metering. For example, the existing language did not address the use of Interval Data Recording meters. The revisions to Schedule 15 also better define responsibilities between APS and the customer regarding the cost responsibility for specialized metering and addresses technical aspects of meter installations.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

Appendix A
Statement of Qualifications
David J. Rumolo

David J. Rumolo is Arizona Public Service Company's Manager of State Pricing. He has over 29 years experience in the electric utility business as a consultant and utility professional. Mr. Rumolo holds Bachelor of Science Degrees in Electrical Engineering and Business (Finance as an area of emphasis) from the University of Colorado. He is a registered professional engineer in the states of Arizona, California, Colorado, and New Mexico.

Mr. Rumolo's areas of expertise include utility rate design; embedded and marginal cost analysis; formulation of utility service policies; contract development and negotiation; utility valuation analyses; and evaluation of utility revenue requirements. Mr. Rumolo has testified on utility matters before state regulatory bodies in the states of Arizona, Colorado, Florida, and Wyoming and before judicial bodies in the states of Arizona and California. Mr. Rumolo is also experienced in the many aspects of electric utility planning and design including preparation of long range resource plans; transmission and distribution system long range planning; system protection analyses; and reliability assessments.

Mr. Rumolo has held his current position at Arizona Public Service Company for approximately three years. Prior to assuming that position, he served as the Manager of Transmission and Market Structure Assessment for Pinnacle West Energy Corporation ("PWEC"). Before joining PWEC, Mr. Rumolo had a 15-year career as a consultant with Resource Management International, Inc., where he provided utility rate and engineering consulting services to utility clients across the United States and overseas. He began his career providing consulting services to utility clients when he joined the firm of Miner and Miner Consulting Engineers in Greeley, Colorado where he became the Manager of Planning and Rates. He later became a partner in Electrical

Systems Consultants where he focused on cost of service and rate analyses, as well as transmission and distribution planning.

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APPENDIX B

The following TERMS AND CONDITIONS and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (Company), under the established rate or rates authorized by law and currently applicable at time of sale.

1. General

1.1 Services will be supplied in accordance with these Terms and Conditions and any changes required by law, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of the customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required.

1.2 These Terms and Conditions shall be considered a part of all rate schedules, except where specifically changed by a written agreement.

1.3 In case of a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule shall apply.

1.4 Company will supply electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and is responsible for distribution services, emergency system conditions, outages and safety situations related to Company's distribution system.

2. Establishment of Service

2.1 Application for Service - Customers requesting service may be required to appear at Company's place of business to produce proof of identity and sign Company's standard form of application for service or a contract before service is supplied by Company.

2.1.1 In the absence of a signed application or contract for service, the supplying of Standard Offer and/or Direct Access services by Company and acceptance thereof by the customer shall be deemed to constitute a service agreement by and between Company and the customer for delivery of, acceptance of, and payment for service, subject to Company's applicable rates and rules and regulations.

2.1.2 Where service is requested by two or more individuals, Company shall have the right to collect the full amount owed Company from any one of the applicants.

2.1.3 In mobile home parks identified by Company as being seasonal parks, Company may install or connect a meter as its scheduling permits; however, the customer will only be responsible for energy and demand recorded on and after their requested service turn on date.

2.2 Service Establishment Charge - A service establishment charge of $25.00 for residential and $35.00 non-residential plus any applicable tax adjustment will be assessed each time Company is requested to establish, reconnect or re-establish electric service to the customer's delivery point, or to make a special read without a disconnect and calculate a bill for a partial month. Billing for the service charge will be rendered as part of the service bill, but not later than the second service bill.

The service establishment charges above may be assessed when a customer changes their rate selection from Direct Access to Standard Offer.

2.2.1 The customer may additionally be required to pay a trip charge of $17.50 when an authorized Company representative travels to the customer's site and is unable to complete the customer's requested services due to lack of access to meter panel.

2.2.2 The customer may additionally be required to pay an after-hour charge of $75.00 should the customer request service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established during a period other than regular working hours, or on the same day of their request, regardless of the time the order may be worked by Company.

2.2.3 The charge for Company work, requested by the customer to be worked after hours or on a Company holiday that does not meet the definition of A.A.C. R14-2-203.D.3 will be billed at current hourly rates as determined by Company.

2.3 Direct Access Service Request (DASR) - A Direct Access Service Request charge of $10.00 plus any applicable tax adjustment will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in the Company's Schedule 10, Terms and Conditions for Direct Access.

2.4 Grounds for Refusal of Service - Company may refuse to connect or reconnect Standard Offer or Direct Access service if any of the following conditions exist:

2.4.1 The applicant has an outstanding amount due with Company for the same class of service and is unwilling to make payment arrangements that are acceptable to Company.

2.4.2 A condition exists which in Company's judgment is unsafe or hazardous.

2.4.3 The applicant has failed to meet the security deposit requirements set forth by Company as specified under Section 2.6 hereof.

2.4.4 The applicant is known to be in violation of Company's tariff.

2.4.5 The applicant fails to furnish such funds, service, equipment, and/or rights-of-way or easements required to serve the applicant and which have been specified by Company as a condition for providing service.

2.4.6 The applicant falsifies his or her identity for the purpose of obtaining service.

2.4.7 Service is already being provided at the address for which the applicant is requesting service.

2.4.8 Service is requested by an applicant and a prior customer living with the applicant owes a delinquent bill.

2.4.9 The applicant is acting as an agent for a prior customer who is deriving benefits of the service and who owes a delinquent bill.

2.4.10 The applicant has failed to obtain all required permits and/or inspections indicating that the applicant's facilities comply with local construction and safety codes.

2.5 Establishment of Credit or Security Deposit

2.5.1 Residential Establishment of Credit - Company shall not require a security deposit from a new applicant for residential service if the applicant is able to meet any of the following requirements:

2.5.1.1 The applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.1.2 Company receives an acceptable credit rating, as determined by Company, for the applicant from a credit rating agency utilized by Company.

2.5.1.3 In lieu of a security deposit, Company receives deposit guarantee notification from a social or governmental agency acceptable to Company or a surety bond as security for Company in a sum equal to the required deposit.

2.5.2 Residential Establishment of Security Deposit - When credit cannot be established as provided for in Section 2.5.1 hereof or when it is determined that the applicant left an unpaid final bill owing to another utility company, the applicant will be required to:

2.5.2.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.2.2 Provide a surety bond acceptable to Company in an amount equal to the required security deposit.

2.5.3 Nonresidential Establishment of Security Deposit - All nonresidential customers may be required to:

2.5.3.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.3.2 Provide a non-cash security deposit in the form of a Surety Bond, Irrevocable Letter of Credit, or Assignment of Monies in an amount equal to the required security deposit.

2.6 Reestablishment of Security Deposit

2.6.1 Residential - Company may require a residential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or has been disconnected for non-payment during the last twelve (12) months.

2.6.2 Nonresidential - Company may require a nonresidential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a six (6) consecutive month period or if the customer has been disconnected for non-payment during the last twelve (12) months, or when the customer's financial condition may jeopardize the payment of their bill, as determined by Company based on the results of using a credit scoring worksheet. Company will inform all customers of the Arizona Corporation Commission's complaint process should the customer dispute the deposit based on the financial data.

2.7 Security Deposits

2.7.1 Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by the Company:

2.7.1.1 If the customer's average consumption increases by more than ten (10) percent for residential accounts within a twelve (12) consecutive month period and five (5) percent for nonresidential accounts within a twelve (12) consecutive month period; or,

2.7.1.2 If the customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount which reflects that portion of the customer's service being provided by a Load Serving ESP. However if the Load Serving ESP is providing ESP Consolidated Billing pursuant to Company's Schedule 10 Section 7, the entire deposit will be credited to the customer's account; or,

2.7.1.3 If the customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount pursuant to Section 2.5, which reflects that APS is providing bundled electric service.

2.7.2 Separate security deposits may be required for each service location.

2.7.3 Customer security deposits shall not preclude Company from terminating an agreement for service or suspending service for any failure in the performance of customer obligation under the agreement for service.

2.7.4 Cash deposits held by Company six (6) months/183 days or longer shall earn interest at the established one year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website. Deposits on inactive accounts are applied to the final bill when all service options become inactive, and the balance, if any, is refunded to the customer of record within thirty (30) days. For refunds resulting from the customer changing from Standard Offer to Direct Access, the difference in the deposit amounts will be applied to the customer's account.

2.7.5 If the customer terminates all service with Company, the security deposit may be credited to the customer's final bill.

2.7.6 Residential security deposits shall not exceed two (2) times the customer's average monthly bill as estimated by Company for the services being provided by the Company.

2.7.6.1 Deposits or other instruments of credit will automatically expire or be returned or credited to the customers account after twelve (12) consecutive months of service, provided the customer has not been delinquent more than twice, unless Customer has filed bankruptcy in the last 12 months.

2.7.7 Nonresidential security deposits shall not exceed two and one-half (2-1/2) times the customer's maximum monthly billing as estimated by Company for the service being provided by the Company.

2.7.7.1 Deposits and non-cash deposits on file with Company will be reviewed after twenty-four (24) months of service and will be returned provided the customer has not been delinquent more than twice in the payment of bills or disconnected for non-payment during the previous twelve (12) consecutive months unless the customer's financial condition warrants extension of the security deposit.

2.8 Line Extensions - Installations requiring Company to extend its facilities in order to establish service will be made in accordance with Company's Schedule #3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

3. Rates

3.1 Rate Information - Company shall provide, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to that customer for the requested type of service. In addition, Company shall notify its customers of any changes in Company tariffs affecting those customers.

3.2 Rate Selection – The customer's service characteristics and service requirements determine the selection of applicable rate schedule. If the customer is being served on a Standard Offer rate, Company will use reasonable care in initially establishing service to the customer under the most advantageous Standard Offer rate schedule applicable to the customer. However, because of varying customer usage patterns and other reasons beyond its reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. Company will not make any refunds in any instances where it is determined that the customer would have paid less for service had the customer been billed on an alternate applicable rate or provision of that rate.

3.3 Standard Offer Optional Rates – Certain optional Standard Offer rate schedules applicable to certain classes of service allow the customer the option to select the rate schedule to be effective initially or after service has been established. A customer desiring service under an alternate rate schedule after service has been established must make such request in writing to Company. Billing under the alternate rate will become effective from the next meter reading, or when the appropriate metering equipment is installed. No further rate schedule changes, however, may be made within the succeeding twelve-month period. Where the rate schedule or contract pursuant to which the customer is provided service specifies a term, the customer may not exercise its option to select an alternate rate schedule until expiration of that term.

3.4 Direct Access rate selection will be effective upon the next meter read date if DASR is processed fifteen (15) calendar days prior to that read date and the appropriate metering equipment is in place. If a DASR is made less than fifteen (15) days prior to the next regular read date the effective date will be at the next meter read date thereafter. The above timeframes are applicable for customers changing their selection of Electric Service Providers or for customers returning to Standard Offer service.

3.5 Any customer making a Direct Access rate selection may return to Standard Offer service in accordance with the rules, regulations, and orders of the Commission. However, such customer will not be eligible for Direct Access for the succeeding twelve (12) month period. If a customer returning to Standard Offer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will only apply if the customer fails to select another ESP within sixty (60) days of returning to Standard Offer.

4. Billing and Collection

4.1 Customer Service Installation and Billing - Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules, through contractual agreement, or at Company option.

4.1.1 Company normally meters and bills each site separately; however, adjacent and contiguous sites not separated by private or public property or right of way and operated as one integral unit under the same name and as a part of the same business, will be considered a single site as specified in Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

4.1.2 The customer's service installation will normally be arranged to accept only one type of service at one point of delivery to enable service measurement through one meter. If the customer requires more than one type of service, or total service cannot be measured through one meter according to Company's regular practice, separate meters will be used and separate billing rendered for the service measured by each meter.

4.2 Collection Policy - The following collection policy shall apply to all customer accounts:

4.2.1 All bills rendered by Company are due and payable no later than fifteen (15) days from the billing date. Any payment not received within this time frame shall be considered delinquent. All delinquent bills for which payment has not been received shall be subject to the provisions of Company's termination procedure. Company reserves the right to suspend or terminate the customer's service for non-payment of any Arizona Corporation Commission approved services. All delinquent charges will be subject to a late charge at the rate of eighteen percent (18%) per annum.

4.2.2 If the customer, as defined in A.A.C. R 14-2-201.9 , has two or more services with Company and one or more of such services is terminated for any reason leaving an outstanding bill and the customer is unwilling to make payment arrangements that are acceptable to Company, Company shall be entitled to transfer the balance due on the terminated service to any other active account of the customer for the same class of service. The failure of the customer to pay the active account shall result in the suspension or termination of service thereunder.

4.2.3 Unpaid charges incurred prior to the customer selecting Direct Access will not delay the customer's request for Direct Access. These charges remain the responsibility of the customer to pay. Normal collection activity, including discontinuing service, may be followed for failure to pay.

4.3 Responsibility for Payment of Bills

4.3.1 The customer is responsible for the payment of bills until service is ordered discontinued and Company has had reasonable time to secure a final meter reading for those services involving energy usage, or if non-metered services are involved until the Company has had reasonable time to process the disconnect request.

4.3.2 When an error is found to exist in the billing rendered to the customer, Company will correct such an error to recover or refund the difference between the original billing and the correct billing. Such adjusted billings will not be rendered for periods in excess of the applicable statute of limitations from the date the error is discovered. Any refunds to customers resulting from overbillings will be made promptly upon discovery by Company. Underbillings by Company shall be billed to the customer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion. Except in situations where the account is billed on a special contract or non-metered rate, where service has been established but no bills have been rendered, or where there is evidence of meter tampering or energy diversion, underbillings for residential accounts shall be limited to three (3) months and non-residential accounts shall be limited to six (6) months.

4.3.3 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of up to $10.00 per customer to customers who elect to pay their bills using Company's electronically transmitted payment options.

4.3.4 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of $5.00 per customer for a customer electing to forego the presentation of a paper bill.

4.4 Dishonored Payments - If Company is notified by the customer's financial institution that they will not honor a payment tendered by the customer for payment of any bill, Company may require the customer to make payment in cash, by money order, certified check, or other means which guarantee the customer's payment to Company.

4.4.1 The customer shall be charged a fee of $15.00 for each instance where the customer tenders payment of a bill with a payment that is not honored by the customer's financial institution.

4.4.2 The tender of a dishonored payment shall in no way (i) relieve the customer of the obligation to render payment to Company under the original terms of the bill, or (ii) defer Company's right to terminate service for nonpayment of bills.

4.4.3 Where the customer has tendered two (2) or more dishonored payments in the past twelve (12) consecutive months, Company may require the customer to make payment in cash, money order or cashier's check for the next twelve (12) consecutive months.

4.5 Field Call Charge - Company may require payment of a Field Call Charge of $15.00 when an authorized Company representative travels to the customer's site to accept payment of a delinquent account, notify of service termination, make payment arrangements or terminate the service. This charge will only be applied for field calls resulting from the termination process.

4.5.1 If a termination is required at the pole, a reconnection charge of $100.00 will be required; if the termination is in underground equipment, the reconnection charge will be $125.00.

4.5.2 To avoid termination of service, the customer may make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.

4.6 On-site Evaluation – Company may require payment of an On-site Evaluation Charge of $90.00 when an authorized Company field investigator performs an on-site visit to evaluate how the customer may reduce their energy usage. This charge may be assessed regardless of if the customer actually implements Company suggestions.

5. Service Responsibilities of Company and Customer

5.1 Service Voltage –Company will deliver electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and as specified in A.A.C. R14-2-208.F.

5.2 Responsibility: Use of Service or Apparatus

5.2.1 The customer shall save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or the use thereof on the customer's side of the point of delivery. Company shall have the right to suspend or terminate service in the event Company should learn of service use by the customer under hazardous conditions.

5.2.2 The customer shall exercise all reasonable care to prevent loss or damage to Company property installed on the customer's site for the purpose of supplying service to the customer.

5.2.3 The customer shall be responsible for payment for loss or damage to Company property on the customer's site arising from neglect, carelessness or misuse and shall reimburse Company for the cost of necessary repairs or replacements.

5.2.4 The customer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the meter.

5.2.5 The customer shall be responsible for notifying Company of any failure in Company's equipment.

5.3 Service Interruptions: Limitations on Liability of Company

5.3.1 Company shall not be liable to the customer for any damages occasioned by Load Serving ESP's equipment or failure to perform, fluctuations, interruptions or curtailment of electric service except where due to Company's willful misconduct or gross negligence. Company may, without incurring any liability therefore, suspend the customer's electric service for periods reasonably required to permit Company to accomplish repairs to or changes in any of Company's facilities. The customer needs to protect their own sensitive equipment from harm caused by variations or interruptions in power supply.

5.3.2 In the event of a national emergency or local disaster resulting in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

5.4 Company Access to Customer Sites - Company's authorized agents shall have unassisted access to the customer's sites at all reasonable hours to install, inspect, read, repair or remove its meters or to install, operate or maintain other Company property, or to inspect and determine the connected electrical load. If, after six (6) months (not necessarily consecutive) of good faith efforts by Company to deal with the customer, Company in its opinion does not have unassisted access to the meter, then Company shall have sufficient cause for termination of service or denial of any existing rate options where access is required. The remedy for unassisted access will be at Company discretion and may include the installation by Company of a specialized meter. If such specialized meter is installed, the customer will be billed the difference between the otherwise applicable meter for their rate and the specialized meter. If service is terminated as a result of failure to provide unassisted access, Company verification of unassisted access may be required before service is restored.

5.5 Easements

5.5.1 All suitable easements or rights-of-way required by Company for any portion of the extension which is on sites owned, leased or otherwise controlled by the customer shall be furnished in Company's name by the customer without cost to Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.5.2 When Company discovers that the customer or the customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow adjacent to or within an easement or right-of-way or Company-owned equipment, and such work, construction, vegetation or facility poses a hazard or is in violation of federal, state, or local laws, ordinances, statutes, rules or regulations, or significantly interferes with Company's safe use, operation or maintenance of, or access to, equipment or facilities, Company shall notify the customer or the customer's agent and shall take whatever actions are necessary to eliminate the hazard, obstruction, interference or violation at the customer's expense.

5.6 Load Characteristics – The customer shall exercise reasonable care to assure that the electrical characteristics of its load, such as deviation from sine wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in demand, shall not impair service to other customers or interfere with operation of telephone, television, or other communication facilities. The deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. In situations where Company suspects that a customer's load has a non-conforming power factor, Company may install at its cost the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

6. Metering and Metering Equipment

6.1 Customer Equipment - The customer shall install and maintain all wiring and equipment beyond the point of delivery. Except for Company's meters and special equipment, the customer's entire installation must conform to all applicable construction standards and safety codes and the customer must furnish an inspection or permit if required by law or by Company.

6.1.1 The customer shall provide, in accordance with Company's current service standards and/or Electric Service Requirements Manual, at no expense to Company, and close to the point of delivery, a sufficient and suitable space acceptable to Company's agent for the installation, accessibility and maintenance of Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line at http://esp.apsc.com/resource/metering.

6.1.2 If telephone lines or any other devices are required to read the customer's meter, the customer is responsible for the installation, maintenance, and usage fees at no cost to Company.

6.1.3 Where a customer requests, and Company approves, a special meter reading device to accommodate the customer's needs, the cost for such additional equipment shall be the responsibility of the customer.

6.2 Company Equipment

6.2.1 A Load Serving ESP or their authorized agents may remove Company's metering equipment pursuant to Company's Schedule 10. Meters not returned to Company or returned damaged will be charged the replacement costs less five (5) years depreciation plus an administration fee of fifteen percent (15%).

6.2.2 Company will lease lock ring keys to Load Serving ESP's and/or their agents authorized to remove Company meters pursuant to the terms and conditions of Company's Schedule 10 at a refundable charge of $70.00 per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace ten percent (10%) of the issued keys within any twelve (12) month period due to loss by the ESP's agent, Company may, rather than leasing additional lock ring keys, require the ESP to arrange for a joint meeting. All lock ring keys must be returned to Company within five (5) working days if the Load Serving ESP and/or their authorized agents are:

1) No longer permitted to remove Company meters pursuant to conditions of the Company's Schedule 10;
2) No longer authorized by the Arizona Corporation Commission to provide services; or
3) The ESP Agreement has been terminated.

6.2.3 If the Load Serving ESP, the customer, and/or its' agent request a joint site meeting for removal of Company metering and associated equipment and/or lock ring, a base charge will be assessed of $70.00 per site. Company may assess an additional charge, based on the current hourly rate as determined by Company, for joint site meetings that exceed thirty (30) minutes. In the event Company must temporarily replace the ESP's meter and/or associated metering equipment as necessary during emergency situations or to restore power to a customer, the above charges may apply.

6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the customer's side of the point of delivery except its meter. For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider. For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinet necessary for the installation of Company's underground service conductors. For the mutual protection of the customer and Company, only authorized employees or agents of Company or the Load Serving ESP are permitted to make and energize the connection between Company's service wires and the customer's service entrance conductors. Such employees carry credentials which they will show on request.

6.4 Measuring Customer Service - All the energy sold to the customer will be measured by commercially acceptable measuring devices by Company or the Load Serving ESP pursuant to the terms and conditions of Company's Schedule 10. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company.

6.4.1 For Standard Offer customers, or where Company is the Meter Reading Service Provider (MRSP), the readings of the meter will be conclusive as to the amount of electric power supplied to the customer unless there is evidence of meter tampering or energy diversion, or unless a test reveals the meter is in error by more than plus or minus three percent (3%).

6.4.2 If there is evidence of meter tampering or energy diversion, the customer will be billed for the estimated energy consumption that would have registered had all energy usage been properly metered. Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer may also be charged the cost of the investigation as determined by Company.

6.4.3 If after testing, a meter is found to be more than three percent (3%) in error, either fast or slow, proper correction shall be made of previous readings and adjusted bills shall be rendered or adjusted billing information will be provided to the ESP.

6.4.4 Customer will be billed for the estimated energy and demand that would have registered had the meter been operating properly. Where Company is the MRSP, Company shall, at the request of the customer or the ESP, reread the customer's meter within ten (10) working days after such request by the customer. The cost of such rereads is $20.00 and may be charged to the customer or the ESP, provided that the original reading was not in error.

6.4.5 Where the ESP is the Meter Service Provider (MSP) or (MRSP), and the ESP and/or its' agent fails to provide the meter data to Company pursuant to Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, Company may obtain the data, or may estimate the billing determinants. The charge for such reread is $20.00 and may be charged to the ESP.

6.5 Meter Testing - Company tests its meters regularly in accordance with a meter testing and maintenance program as approved by the Arizona Corporation Commission. Company will, however, individually test a Company owned/maintained meter upon customer or ESP request. If the meter is found to be within the plus or minus three percent (3%) limit, Company may charge the customer or the ESP $30.00 for the meter test if the meter is removed from the site and tested in the meter shop, and $100.00 if the meter remains on site and is tested in the field.

6.6 Master Metering

6.6.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

6.6.2 Residential Apartment Complexes, Condominiums and Other Multiunit Residential Buildings - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered unless the building(s) will be served by a centralized heating, ventilation and/or air conditioning system and the contractor can provide to Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in A.A.C. R14-2-205.

7. Termination of Service

7.1 With Notice - Company may without liability for injury or damage, and without making a personal visit to the site, disconnect service to any customer for any of the reasons stated below, provided Company has met the notice requirements established by the Arizona Corporation Commission:

7.1.1 A customer violation of any of the applicable rules of the Arizona Corporation Commission or Company tariffs.

7.1.2 Failure of the customer to pay a delinquent bill for services provided by Company.

7.1.3 The customer's breach of a written contract for service.

7.1.4 Failure of the customer to comply with Company's deposit requirements.

7.1.5 Failure of the customer to provide Company with satisfactory and unassisted access to Company's equipment.

7.1.6 When necessary to comply with an order of any governmental agency having jurisdiction.

7.1.7 Failure of a prior customer to pay a delinquent bill for utility services where the prior customer continues to reside on the premises.

7.1.8 Failure to provide or retain rights-of-way or easements necessary to serve the customer.

7.2 Without Notice - Company may without liability for injury or damage disconnect service to any customer without advance notice under any of the following conditions:

7.2.1 The existence of an obvious hazard to the health or safety of persons or property.

7.2.2 Company has evidence of meter tampering or fraud.

7.2.3 Company has evidence of unauthorized resale or use of electric service.

7.2.4 Failure of the customer to comply with the curtailment procedures imposed by Company during a supply shortage.

7.3 Restoration of Service - Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.

8. Removal of Facilities - Upon termination of service, Company may without liability for injury or damage, dismantle and remove its facilities installed for the purpose of supplying service to the customer, and Company shall be under no further obligation to serve the customer. If, however, Company has not removed its facilities within one (1) year after the termination of service, Company shall thereafter give the customer thirty (30) days written notice before removing its facilities, or else waive any reestablishment charge within the next year for the same service to the same customer at the same location.

For purposes of this Section notice to the customer shall be deemed given at the time such notice is deposited in the U.S. Postal Service, first class mail, postage prepaid, to the customer at his/her last known address.

9. Successors and Assigns - Agreements for Service shall be binding upon and for the benefit of the successors and assigns of the customer and Company, but no assignments by the customer shall be effective until the customer's assignee agrees in writing to be bound and until such assignment is accepted in writing by Company.

10. Warranty - THERE ARE NO UNDERSTANDINGS, AGREEMENTS, REPRESENTATIONS, OR WARRANTIES, EXPRESS OR IMPLIED (INCLUDING WARRANTIES REGARDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), NOT SPECIFIED HEREIN OR IN THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION CONCERNING THE SALE AND DELIVERY OF SERVICES BY COMPANY TO THE CUSTOMER. THESE TERMS AND CONDITIONS AND THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION STATE THE ENTIRE OBLIGATION OF COMPANY IN CONNECTION WITH SUCH SALES AND DELIVERIES.

SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

The following TERMS AND CONDITIONS and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (Company), under the established rate or rates authorized by law and currently applicable at time of sale.

1. General

1.1 Services will be supplied in accordance with these Terms and Conditions and any changes required by law, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of the cCustomer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required.

1.2 These Terms and Conditions shall be considered a part of all ~~Standard Offer and Direct Access~~ rate schedules, except where specifically changed by a written agreement.

1.3 In case of a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule shall apply.

1.4 ~~The~~ Company will supply electric service at the standard voltages specified in the Electric Service Requirements Mmanual published by ~~the~~ Company and is responsible for distribution services, emergency system conditions, outages and safety situations related to ~~APS'~~ Company's distribution system.

2. Establishment of Service

2.1 Application for Service - Customers requesting service may be required to appear at Company's place of business to produce proof of identity and sign Company's standard form of application for service or a contract before service is supplied by Company.

2.1.1 In the absence of a signed application or contract for service, the supplying of Standard Offer and/or Direct Access services by Company and acceptance thereof by the cCustomer shall be deemed to constitute a service agreement by and between Company and the cCustomer for delivery of, acceptance of, and payment for service, subject to Company's applicable rates and rules and regulations.

2.1.2 Where service is requested by two or more individuals, Company shall have the right to collect the full amount owed Company from any one of the applicants.

2.1.3 In mobile home parks identified by Company as being seasonal parks, Company may install or connect a meter as its scheduling permits; however, the customer will only be responsible for energy and demand recorded on and after their requested service turn on date.

2.2 Service Establishment Charge - A service establishment charge of $25.00 for residential and $35.00 non-residential ~~for electric service and the appropriate tax adjustment~~plus any applicable tax adjustment will be assessed each time Company is requested to establish, reconnect or re-establish electric service to the cCustomer's delivery point, or to make a special read without a disconnect and calculate a bill for a partial month. Billing for the service charge will be rendered as part of the service bill, but not later than the second service bill. The service establishment charges above may be assessed when a customer changes their rate selection from Direct Access to Standard Offer.

2.2.1 The customer may additionally be required to pay a trip charge of $17.50 when an authorized Company representative travels to the customer's site and is unable to complete the customer's requested services due to lack of access to meter panel.

~~2.2.1~~2.2.2 The cCustomer may additionally be required to pay an after-hour charge of $~~50~~75.00 should the cCustomer request service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established during a period other than regular working hours, or on the same day of their request, regardless of the time the order may be worked by Company.

2.2.3 The charge for Company work, requested by the customer to be worked after hours or on a Company holiday that does not meet the definition of A.A.C. R14-2-203.D.3 will be billed at current hourly rates as determined by Company.

2.3 Direct Access Service Request (DASR) - A Ddirect Aaccess Sservice Rrequest charge of $10.00 plus any applicable tax adjustment ~~and the appropriate tax adjustment~~ will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in the Company's Schedule 10, Terms and Conditions for Direct Access.

2.4 Grounds for Refusal of Service - Company may refuse to connect or reconnect Standard Offer or Direct Access service if any of the following conditions exist:

2.4.1 The aApplicant has an outstanding amount due with Company for the same class of service and is unwilling to make payment arrangements that are acceptable to ~~with~~ Company ~~for payment~~.

2.4.2 A condition exists which in Company's judgment is unsafe or hazardous.

2.4.3 The aApplicant has failed to meet the security deposit requirements set forth by Company as specified under Section 2.6 hereof.

2.4.4 The aApplicant is known to be in violation of Company's tariffs.

2.4.5 The aApplicant fails to furnish such funds, service, equipment, and/or rights-of-way or easements required to serve the aApplicant and which have been specified by Company as a condition for providing service.

2.4.6 The aApplicant falsifies his or her identity for the purpose of obtaining service.

2.4.7 Service is already being provided at the address for which the aApplicant is requesting service.

2.4.8 Service is requested by an aApplicant and a prior cCustomer living with the aApplicant owes a delinquent bill.

2.4.9 The aApplicant is acting as an agent for a prior cCustomer who is deriving benefits of the service and who owes a delinquent bill.

2.4.10 The aApplicant has failed to obtain all required permits and/or inspections indicating that the aApplicant's facilities comply with local construction and safety codes.

2.5 Establishment of Credit or Security Deposit

2.5.1 Residential Establishment of Credit - Company shall not require a security deposit from a new aApplicant for residential service if the aApplicant is able to meet any of the following requirements:

2.5.1.1 The aApplicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.1.2 Company receives an acceptable credit rating, as determined by Company, for the applicant from a credit rating agency utilized by Company.~~Applicant can produce a letter regarding credit or verification from an electric utility where service of a comparable nature was last received which states Applicant had a timely payment history at time of service discontinuation.~~

2.5.1.3 In lieu of a security deposit, Company receives deposit guarantee notification from a social or governmental agency acceptable to ~~the~~ Company or a surety bond as security for Company in a sum equal to the required deposit.

2.5.2 Residential Establishment of Security Deposit - When credit cannot be established as provided for in Section 2.5.1 hereof or when it is determined that the aApplicant left an unpaid final bill owing to another utility company, the aApplicant will be required to:

2.5.2.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.2.2 Provide a surety bond acceptable to Company in an amount equal to the required security deposit.

2.5.3 Nonresidential Establishment of Security Deposit - All nonresidential customers may be required to:

2.5.3.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.3.2 Provide a non-cash security deposit in the form of a Surety Bond, Irrevocable Letter of Credit, or Assignment of Monies in an amount equal to the required security deposit.

2.6 Reestablishment of Security Deposit

2.6.1 Residential - Company may require a residential cCustomer to establish or re-establish a security deposit if the cCustomer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or has been disconnected for non-payment during the last twelve (12) months.

2.6.2 Nonresidential - Company may require a nonresidential cCustomer to establish or re-establish a security deposit if the cCustomer becomes delinquent in the payment of two (2) or more bills within a six (6) consecutive month period or if the cCustomer has been disconnected for non-payment during the last twelve (12) months, or when the cCustomer's financial condition may jeopardize the payment of their bill, as determined by Company based on the results of using a credit scoring worksheet. Company will inform all cCustomers of the Arizona Corporation Commission's complaint process should the cCustomer dispute the deposit based on the financial data.

2.7 Security Deposits

2.7.1 Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by the Company:

2.7.1.1 If the cCustomer's average consumption increases by more than ten (10) percent for residential accounts within a twelve (12) consecutive month period and five (5) percent for nonresidential accounts within a twelve (12) consecutive month period; or,

2.7.1.2 If the cCustomer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount, which reflects that portion of the customer's service being provided by a Lload Sserving ESP. However if the Load Serving ESP is providing ESP Consolidated Billing pursuant to ~~the~~ Company's Schedule 10 Section 7, the entire deposit will be credited to the customer's account; or, 2.7.1.3 If the ~~c~~Customer chooses to change from Direct Access ~~services~~ to Standard Offer service, the requested deposit amount may be increased by an amount pursuant to ~~S~~section 2.5, which reflects that APS is providing bundled electric service.

2.7.2 Separate security deposits may be required for each service location.

2.7.3 Customer security deposits shall not preclude Company from terminating an agreement for service or suspending service for any failure in the performance of ~~c~~Customer obligation under the agreement for service.

2.7.4 Cash deposits held by ~~the~~ Company six (6) months/183 days or longer shall earn interest at the established one year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website. Deposits on inactive accounts are applied to the final bill when all service options become inactive, and the balance, if any, is refunded to the ~~c~~Customer of record within thirty (30) days. For refunds resulting from the customer changing from Standard Offer to Direct Access, the difference in the deposit amounts will be applied to the customer's account.

2.7.5 If the ~~c~~Customer terminates all service with Company, the security deposit may be credited to the ~~c~~Customer's final bill.

2.7.6 Residential security deposits shall not exceed two (2) times the ~~c~~Customer's average monthly bill as estimated by Company for the services being provided by the Company.

2.7.6.1 Deposits or other instruments of credit will automatically expire or be returned or credited to the customers account after twelve (12) consecutive months of service, provided the ~~c~~Customer has not been delinquent more than twice, unless Customer has filed bankruptcy in the last 12 months.

2.7.7 Nonresidential security deposits shall not exceed two and one-half (2-1/2) times the ~~c~~Customer's maximum monthly billing as estimated by ~~the~~ Company for the service being provided by the Company.

2.7.7.1 Deposits and non-cash deposits on file with ~~the~~ Company will be reviewed after twenty-four (24) months of service and will be returned provided the ~~c~~Customer has not been delinquent more than twice in the payment of bills or disconnected for non-payment during the previous twelve (12) consecutive months unless the ~~c~~Customer's financial condition warrants extension of the security deposit.

2.8 Line Extensions - Installations requiring Company to extend its facilities in order to establish service will be made in accordance with Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

3. Rates

3.1 Rate Information - Company shall provide, in accordance ~~to~~ with A.A.C. ~~Commission Rule,~~ R14-2-204, a copy of any rate schedule applicable to that c~~C~~ustomer for the requested type of service. In addition, Company shall notify its c~~C~~ustomers of any changes in Company's tariffs affecting those c~~C~~ustomers.

3.2 Rate Selection – ~~-~~ The c~~C~~ustomer's service characteristics and service requirements determine the selection of applicable rate schedule. If the c~~C~~ustomer is being served on a Standard Offer rate, ~~the~~ Company will use reasonable care in initially establishing service to the c~~C~~ustomer under the most advantageous Standard Offer rate schedule applicable to the c~~C~~ustomer. However, because of varying c~~C~~ustomer usage patterns and other reasons beyond its reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. Company will not make any refunds in any instances where it is determined that the c~~C~~ustomer would have paid less for service had the c~~C~~ustomer been billed on an alternate applicable rate or provision of that rate.

3.3 Standard Offer Optional Rates – Certain optional S~~s~~tandard O~~o~~ffer rate schedules applicable to certain classes of service allow the c~~C~~ustomer the option to select the rate schedule to be effective initially or after service has been established. A c~~C~~ustomer desiring service under an alternate rate schedule after service has been established must make such request in writing to Company. Billing under the alternate rate will become effective from ~~or after~~ the next meter reading, or when the appropriate metering equipment is installed~~-place~~. No further rate schedule changes, however, may be made within the succeeding twelve-month period. Where the rate schedule or contract pursuant to which the c~~C~~ustomer is provided service specifies a term, the c~~C~~ustomer may not exercise its option to select an alternate rate schedule until expiration of that term.

3.4 Direct Access rate selection will be effective upon the next ~~regular~~ meter read date if ~~the direct access service request~~DASR is processed fifteen (15) calendar days prior to that read date and the appropriate metering equipment is in place. If a ~~direct access service request~~DASR is made less than fifteen (15) days prior to the next regular read date the effective date will be at the next meter read date thereafter. The above timeframes are applicable for customers changing their selection of Electric Service Providers or for customers returning to S~~s~~tandard O~~o~~ffer service~~ in accordance with the rules, regulations, and orders of the Commission~~.

3.5 Any customer making a Direct Access rate selection may return to S~~s~~tandard O~~o~~ffer service in accordance with the rules, regulations, and orders of the Commission. However, such customer will not be eligible for Direct Access for the succeeding twelve (12) month period. If a customer returning to S~~s~~tandard O~~o~~ffer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance~~,~~ with the rules and regulations of the Commission~~,~~ by their Load Serving ESP of its intent to cease providing competitive services then the above provision will only apply if the customer fails to select another ESP within sixty (60) days of returning to S~~s~~tandard O~~o~~ffer.

4. Billing and Collection

4.1 Customer Service Installation and Billing - Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules, through contractual agreement, or at Company option.

4.1.1 ~~The~~ Company normally meters and bills each ~~premise~~ site separately; however, adjacent and contiguous ~~premises~~ sites not separated by private or public property or right of way and operated as one integral unit under the same name and as a part of the same business, will be considered a single ~~premise~~ site as specified in Company's Schedule #4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

4.1.2 The ~~c~~Customer's service installation will normally be arranged to accept only one type of ~~standard~~ service at one point of delivery to enable service measurement through one meter. If the ~~c~~Customer requires more than one type of service, or total service cannot be measured through one meter according to Company's regular practice, separate meters will be used and separate billing rendered for the service measured by each meter.

4.2 Collection Policy - The following collection policy shall apply to all customer accounts:

4.2.1 All bills rendered by ~~the~~ Company are due and payable no later than fifteen (15) days from the billing date. Any payment not received within this time frame shall be considered delinquent. All delinquent bills for which payment has not been received shall be subject to the provisions of Company's termination procedure. Company reserves the right to suspend or terminate the ~~c~~Customer's service for~~: i)~~ non-payment of any Arizona Corporation Commission approved services ~~provided by Company, including but not limited to ii) delinquent service bills; iii) non-payment of service establishment charges; iv) non-payment of security deposits; v) non-payment of meter test charges; vi) non-payment of any dishonored payment charges; vii) non-payment of late charges, viii) non-payment of collection charges~~. All delinquent charges will be subject to a late charge at the rate of eighteen percent (18%) per annum.

4.2.2 If the customer, as defined in A.A.C.~~Section~~ R 14-2-201.9 ~~Definition #9 of the Arizona Administration Code~~, has two or more services with Company and one or more of such services is terminated for any reason leaving an outstanding bill and the ~~c~~Customer is unwilling to make payment arrangements ~~with~~ that are acceptable to Company ~~for payment~~, Company shall be entitled to transfer the balance due on the terminated service to any other active account of the ~~c~~Customer for the same class of service. The failure of the ~~c~~Customer to pay the active account shall result in the suspension or termination of service thereunder.

4.2.3 Unpaid charges incurred prior to the c~~C~~ustomer selecting Direct Access will not delay the customer's request for Direct Access. These charges remain the responsibility of the customer to pay. Normal collection activity, including discontinuing service, may be followed for failure to pay.

4.3 Responsibility for Payment of Bills

4.3.1 The c~~C~~ustomer is responsible for the payment of bills until service is ordered discontinued and ~~the~~ Company has had reasonable time to secure a final meter reading for those services involving energy usage, or if non-metered services are involved until the Company has had reasonable time to process the disconnect request.

4.3.2 When an error is found to exist in the billing rendered to the c~~C~~ustomer, Company will correct such an error to recover or refund the difference between the original billing and the correct billing. Such adjusted billings will not be rendered for periods in excess of the applicable statute of limitations from the date the error is discovered. Any refunds to c~~C~~ustomers resulting from ~~adjusted~~ overbillings will be made promptly upon discovery by Company. Underbillings by Company shall be billed to the c~~C~~ustomer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion. Except in situations where the account is billed on a special contract or non-metered rate, where service has been established but no bills have been rendered, or where there is evidence of meter tampering or energy diversion, underbillings for residential accounts shall be limited to three (3) months and non-residential accounts shall be limited to six (6) months.

4.3.3 Where Company is responsible for ~~producing~~ rendering the c~~C~~ustomer's bill, Company may provide a one time incentive of up to $10.00 per customer ~~maximum~~ to c~~C~~ustomers who elect to pay their bills using ~~the~~ Company's ~~SurePay~~ electronically transmitted payment options.

4.3.4 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of $5.00 per customer for a customer electing to forego the presentation of a paper bill.

4.4 Dishonored Payments - If Company is notified by the c~~C~~ustomer's financial institution that they will not honor a payment tendered by the c~~C~~ustomer for payment of any bill ~~because: (i) there are insufficient funds; (ii) the account has been closed; (iii) Customer has sent a "stop payment" request; or (iv) any other reason the financial institution will not honor Customer's payment~~, Company may require the c~~C~~ustomer to make payment in cash, by money order, certified check, or other means which guarantee the c~~C~~ustomer's payment to ~~the~~ Company.

4.4.1 The c~~C~~ustomer shall be charged a fee of ~~fifteen dollars (~~$15.00~~)~~ for each instance where the c~~C~~ustomer tenders payment of a bill with a payment that is not honored by the c~~C~~ustomer's financial institution.

4.4.2 The tender of a dishonored payment shall in no way (i) relieve the c~~C~~ustomer of the obligation to render payment to Company under the original terms of the bill, or (ii) defer Company's right to terminate service for nonpayment of bills.

4.4.3 Where the c~~C~~ustomer has tendered two (2) or more dishonored payments in the past twelve (12) consecutive months, Company may require the c~~C~~ustomer to make payment in cash, money order or cashier's check for the next ~~six (6)~~twelve (12) consecutive months.

4.5 Field Call Charge - Company may require payment of a Field Call Charge of $15.00 when an authorized Company representative travels to the c~~C~~ustomer's site~~premises~~ to accept payment of a delinquent account, notify of service termination, ~~or~~ make payment arrangements or terminate the service. This charge will only be applied for field calls resulting from the termination process.

4.5.1 If a termination is required at the pole, a reconnection charge of $~~87.50~~100.00 will be required; if the termination is in underground equipment, the reconnection charge will be $125.00.

4.5.2 To avoid ~~discontinuance~~ termination of service, the c~~C~~ustomer may make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.

4.6 On-site Evaluation – Company may require payment of an On-site Evaluation Charge of $~~50.00~~90.00 when an authorized Company field investigator performs an on-site visit to evaluate how the customer may reduce their energy usage. This charge may be assessed regardless of if the customer actually implements ~~the~~ Company suggestions.

5. Service Responsibilities of Company and Customer

5.1 Service Voltage – ~~The~~ Company will deliver electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and as specified in A.A.C. R-14-2-208.F.

5.2 Responsibility: Use of Service or Apparatus

5.2.1 The c~~C~~ustomer shall save ~~and~~ Company ~~each shall save the other~~ harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by ~~the~~ Company or the use thereof on the customer's ~~their respective~~ sides of the point of delivery. Company shall~~, however,~~ have the right to suspend or terminate service in the event Company should learn of service use by the c~~C~~ustomer under hazardous conditions.

5.2.2 The c~~C~~ustomer shall exercise all reasonable care to prevent loss or damage to Company property installed on the c~~C~~ustomer's ~~premise~~ site for the purpose of supplying service to the c~~C~~ustomer.

5.2.3 The c~~C~~ustomer shall be responsible for payment for loss or damage to Company property on the c~~C~~ustomer's ~~premise~~ site arising from neglect, carelessness or misuse and shall reimburse Company for the cost of necessary repairs or replacements.

5.2.4 The c~~C~~ustomer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the meter.

5.2.5 The c~~C~~ustomer shall be responsible for notifying Company of any failure in Company's equipment.

5.3 Service Interruptions: Limitations on Liability of Company

5.3.1 Company shall not be liable to the c~~C~~ustomer for any damages occasioned by Load Serving ESP's equipment or failure to perform, fluctuations, interruptions or curtailment of electric service except where due to Company's willful misconduct or gross negligence. Company may, without incurring any liability therefore, suspend the c~~C~~ustomer's electric service for periods reasonably required to permit Company to accomplish repairs to or changes in any of Company's facilities. The c~~C~~ustomers needs to protect their own sensitive equipment from harm caused by variations or interruptions in power supply.

5.3.2 In the event of a national emergency or local disaster resulting in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other c~~C~~ustomers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

5.4 Company Access to Customer ~~Premises~~ Sites - Company's authorized agents shall have unassisted access to the c~~C~~ustomer's ~~premises~~ sites at all reasonable hours to install, inspect, read, repair or remove its meters or to install, operate or maintain other Company property, or to inspect and determine the connected electrical load. ~~Neglect or refusal on the part of Customer to provide reasonable and unassisted access shall be~~If, after six (6) months (not necessarily consecutive) of good faith efforts by Company to deal with the customer, Company in its opinion does not have unassisted access to the meter, then Company shall have sufficient cause for ~~discontinuance~~ termination of service ~~by Company~~, or denial of any existing rate options where access is required. The remedy for unassisted access will be at Company discretion and may include the installation by Company of a specialized meter. If such specialized meter is installed, the customer will be billed the difference between the otherwise applicable meter for their rate and the specialized meter. ~~However, all conditions existing prior to June 30, 1998 shall be grandfathered.~~If service is terminated as a result of failure to provide unassisted access. Company verification of unassisted access may be required before service is restored.

5.5 Easements

5.5.1 All suitable easements or rights-of-way required by Company for any portion of the extension which is on ~~premises~~ sites owned, leased or otherwise controlled by the c~~C~~ustomer shall be furnished in Company's name by the c~~C~~ustomer without cost to Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.5.2 When Company discovers that the customer or the customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow adjacent to or within an easement or right-of-way or Company-owned equipment, and such work, construction, vegetation or facility poses a hazard or is in violation of federal, state, or local laws, ordinances, statutes, rules or regulations, or significantly interferes with Company's safe use, operation or maintenance of, or access to, equipment or facilities, Company shall notify the customer or the customer's agent and shall take whatever actions are necessary to eliminate the hazard, obstruction, interference or violation at the customer's expense.

5.6 Load Characteristics -- The c~~C~~ustomer shall exercise reasonable care to assure that the electrical characteristics of its load, such as deviation from sine wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in demand, shall not impair service to other customers or interfere with operation of telephone, television, or other communication facilities. The deviation from phase balance shall not be greater than ten percent (10%) at any time. ~~The power factor of the load shall not be less than ninety percent (90%) lagging, but in no event leading, unless agreed to by Company. In the event that Customer does not maintain such power factor, at the option of Company, kVa may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.~~Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. In situations where Company suspects that a customer's load has a non-conforming power factor, Company may install at its cost the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

6. Metering and Metering Equipment

6.1 Customer Equipment- The c~~C~~ustomer shall install and maintain all wiring and equipment beyond the point of delivery. Except for Company's meters and special equipment, the c~~C~~ustomer's entire installation must conform to all applicable construction standards and safety codes and the customer must furnish ~~and if~~ an inspection or permit ~~is~~ if required by law or by Company~~, the same must be furnished by Customer~~.

6.1.1 The c~~C~~ustomer shall provide, in accordance with Company's current service standards and/or Electric Service Requirements M~~m~~anual, at no expense to Company, and close to the point of delivery, a sufficient and suitable space acceptable to Company's ~~representative~~ agent for the installation, accessibility and maintenance of Company's metering equipment. ~~All updates to the Electric Service Requirements manual shall be provided to the ACC Staff in a timely manner.~~ A current version of the Electric Service Requirements Manual is available on-line at http://esp.apsc.com/resource/metering.

6.1.2 If telephone lines or any other devices are required to read the customer's meter, the c~~C~~ustomer is responsible for the installation, ~~and~~ maintenance, and usage fees at no cost to ~~the~~ Company.

6.1.3 Where a customer requests, and Company approves, a special meter reading device to accommodate the customer's needs, the cost for such additional equipment shall be the responsibility of the customer.

6.2 Company Equipment

6.2.1 A Load Serving ~~Entity~~ ESP or their authorized agents may remove ~~the~~ Company's metering equipment pursuant to ~~the~~ Company's Schedule 10. Meters not returned to ~~the~~ Company or returned damaged will be charged the replacement costs less five (5) years depreciation plus an administration fee of fifteen percent (15~~)~~%). ~~Potential transformers (PTs) and current transformers (CTs) not returned to the Company or returned damaged will be charged net book value plus an administrative fee of fifteen (15) %.~~

6.2.2 ~~The~~ Company will lease lock ring keys to Load Serving ~~Entities~~ ESP's and/or their agents authorized to remove Company meters pursuant to the terms and conditions of ~~the~~ Company's Schedule 10 at a refundable charge of $70.00 per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace ten percent (10%)~~%~~ of the issued keys within any twelve (12) month period due to loss by the ~~MSP~~ESP's agent, Company may, rather than leasing additional lock ring keys, require the ESP to arrange for a joint meet. All lock ring keys must be returned to ~~APS~~ Company within five (5) working days if the L~~l~~oad S~~s~~erving ~~entity~~ ESP and/or their authorized agents are:

1) No longer permitted to remove ~~the~~ Company~~'s~~ meters pursuant to conditions of the Company's Schedule 10;~~.~~
2) No longer authorized by the Arizona Corporation Commission to provide services; or~~.~~
3) ~~Or if~~ T~~t~~he ESP Agreement has been terminated.

6.2.3 If the L~~l~~oad S~~s~~erving ESP, the customer, and/or its' agent request a joint site meeting for removal of Company metering and associated equipment and/or lock ring, a base charge will be assessed of $~~30~~70.00 per site ~~for the Phoenix metropolitan area and $75.00 per site for all other areas~~. ~~The~~ Company may assess an additional charge, based on the current hourly rate as determined by Company, ~~of $30.00 per hour~~ for joint site meetings that exceed thirty (30) minutes. In the event Company must temporarily replace the ESP's meter and/or associated metering equipment as necessary during emergency situations or to restore power to a customer, the above charges may apply.

6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the c~~C~~ustomer's side of the point of delivery except its meter. For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider. For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinet necessary for the installation of Company's underground service conductors. For the mutual protection of the c~~C~~ustomer and Company, only authorized employees or agents of ~~the~~ Company or the Load Serving ~~Entity~~ ESP are permitted to make and energize the connection between Company's service wires and the c~~C~~ustomer's service entrance conductors. Such employees carry credentials which they will show on request.

6.4 Measuring Customer Service - All the energy sold to the c~~C~~ustomer will be measured by commercially acceptable measuring devices by ~~the~~ Company or the L~~l~~oad S~~s~~erving ESP pursuant to the terms and conditions of ~~APS'~~ Company's Schedule 10. ~~Except W~~ where it is ~~impracticable~~ impractical to meter loads, such as street lighting, security lighting, or special installations, ~~in which case the~~ consumption ~~may be calculated~~will be determined by Company.

6.4.1 For Standard Offer c~~C~~ustomers, or where Company is the Meter Reading Service Provider (MRSP), the readings of the meter will be conclusive as to the amount of electric power supplied to the c~~C~~ustomer unless~~,~~ there is evidence of meter tampering or energy diversion, or unless a test reveals the meter is in error by more than plus or minus three percent (3%).

6.4.2 If there is evidence of meter tampering or energy diversion, the c~~C~~ustomer will be billed for the estimated energy consumption that would have ~~been~~ registered had all energy usage been properly metered. Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer may also be charged the cost of the investigation as determined by Company.

6.4.3 If ~~any meter~~ after testing, a meter is found to be more than three percent (3%) in error, either fast or slow, proper correction shall be made of previous readings and adjusted bills shall be rendered or adjusted billing information will be provided to the ~~Electric Service Provider~~ESP.

6.4.4 Customer will be billed for the estimated energy ~~consumption~~ and demand that would have ~~been~~ registered had the meter been operating properly. Where Company is the ~~Meter Reading Service Provider~~MRSP, Company shall, at the request of the ~~c~~Customer or the ESP, reread the ~~c~~Customer's meter within ten (10) working days after such request by the ~~c~~Customer. The cost of such rereads ~~, which is $10,~~is $20.00 and may be charged to the ~~c~~Customer or the ESP, provided that the original reading was not in error.

6.4.5 Where the ESP is the Meter Service Provider (MSP) ~~o~~Or ~~Meter Reading Service Provider~~(MRSP), and the ESP and/or its' agent fails to provide the meter ~~read~~ data to ~~APS~~ Company pursuant to ~~the~~ Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, ~~the~~ Company may obtain the ~~read~~data, or may estimate the billing determinants. The ~~cost of~~charge for such reread~~, which~~ is ~~$10~~$20.00~~,~~ and may be charged to the ESP.

6.5 Meter Testing - Company tests its meters regularly in accordance with a meter testing and maintenance program as approved by the Arizona Corporation Commission. Company will, however, individually test a Company owned/maintained meter upon ~~c~~Customer's or ESP's request. If the meter is found to be within the plus or minus three percent (3%) limit, Company may charge the ~~c~~Customer ~~of~~ or the ESP $~~25~~30.00 for the ~~costs of the~~ meter test if the meter is removed from the site and tested in the meter shop, and $100.00 if the meter remains on site and is tested in the field.

6.6 Master Metering

6.6.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by ~~the utility~~Company ~~as stated in R14-2-205 of the Corporation Commission's Administrative Rules and Regulations~~.

6.6.2 Residential Apartment Complexes, Condominiums and Other Multiunit Residential Buildings - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered unless the building(s) will be served by a centralized heating, ventilation and/or air conditioning system and the contractor can provide to ~~the utility~~Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in A.A.C. R14-2-205 ~~of the Corporation Commission's Administrative Rules and Regulations~~.

7. Termination of Service

7.1 With Notice - Company may without liability for injury or damage, and without making a personal visit to the site, disconnect service to any ~~c~~Customer for any of the reasons stated below, provided Company has met the notice requirements established by the Arizona Corporation Commission:

7.1.1 A cCustomer~~'s~~ violation of any of the applicable rules of the Arizona Corporation Commission or Company~~'s~~ tariffs.

7.1.2 Failure of the cCustomer to pay a delinquent bill for services provided by ~~the~~ Company.

7.1.3 The cCustomer's breach of a written contract for service.

7.1.4 Failure of the cCustomer to comply with Company's deposit requirements.

7.1.5 Failure of the cCustomer to provide Company with satisfactory and unassisted access to Company's equipment. ~~However, all conditions existing prior to June 30, 1998 shall be grandfathered.~~

7.1.6 When necessary to comply with an order of any governmental agency having jurisdiction.

7.1.7 Failure of a prior customer to pay a delinquent bill for utility services where the prior customer continues to reside on the premises.

7.1.8 Failure to provide or retain rights-of-way or easements necessary to serve the customer.

7.2 Without Notice - Company may without liability for injury or damage disconnect service to any cCustomer without advance notice under any of the following conditions:

7.2.1 The existence of an obvious hazard to the health or safety of persons or property.

7.2.2 Company has evidence of meter tampering or fraud.

7.2.3 Company has evidence of unauthorized resale or use of electric service.

7.2.4 Failure of the cCustomer to comply with the curtailment procedures imposed by Company during a supply shortage.

7.3 Restoration of Service - Company shall not be required to restore service until the conditions~~,~~ which resulted in the termination~~,~~ have been corrected to the satisfaction of Company.

8. Removal of Facilities - Upon ~~the~~ termination of service, Company may without liability for injury or damage, dismantle and remove its facilities installed for the purpose of supplying service to the cCustomer, and Company shall be under no further obligation to serve the cCustomer. If, however, Company has not removed its facilities within one (1) year after the termination of service, Company shall thereafter give the cCustomer thirty (30) days written notice before removing its facilities, or else waive any reestablishment charge within the next year for the same service to the same cCustomer at the same location.

For purposes of this Section notice to the cCustomer shall be deemed given at the time such notice is deposited in the U.S. Postal Service, first class mail, postage prepaid, to the cCustomer at his/her last known address.

9. Successors and Assigns - Agreements for Service shall be binding upon and for the benefit of the successors and assigns of the cCustomer and Company, but no assignments by the cCustomer shall be effective until the cCustomer's assignee agrees in writing to be bound and until such assignment is accepted in writing by Company.

10. Warranty - THERE ARE NO UNDERSTANDINGS, AGREEMENTS, REPRESENTATIONS, OR WARRANTIES, EXPRESS OR IMPLIED (INCLUDING WARRANTIES REGARDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), NOT SPECIFIED HEREIN OR IN THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION CONCERNING THE SALE AND DELIVERY OF SERVICES BY COMPANY TO THE CUSTOMER. THESE TERMS AND CONDITIONS AND THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION STATE THE ENTIRE OBLIGATION OF COMPANY IN CONNECTION WITH SUCH SALES AND DELIVERIES.

SCHEDULE 2
TERMS AND CONDITIONS FOR ENERGY PURCHASES FROM QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITIES

The following TERMS AND CONDITIONS and any changes authorized by law, regulation, rule or order of applicable governmental authority will apply to the purchase of electric energy under the established rate or rates authorized by law and currently applicable at time of purchase; and these TERMS AND CONDITIONS shall be considered a part of all of Company's rate schedules for purchases except where specifically changed by written agreement.

1. DEFINITIONS

1.1 Point Of Interconnection - The point where Company's service conductors are connected to Customer's service conductors.

1.2 Qualifying Facility (QF) - Any cogeneration or small power production facility that meets the criteria for size, fuel use, efficiency, and ownership as promulgated in 18 CFR, Chapter I, Part 292, Subpart B of the Federal Energy Regulatory Commission's Regulations.

1.3 Purchase Agreement - The agreement entered into between Customer and Company detailing the provisions for the purchase of electric energy by Company from Customer's QF, and the sale, if any, of power by Company to Customer.

1.4 Cogeneration Facility - Any facility that sequentially produces electricity, steam or forms of useful energy (e.g., heat) from the same fuel source and which are used for industrial, commercial, heating, or cooling purposes.

1.5 Small Power Production Facility - A facility that uses primarily biomass, waste, or renewable resources, including wind, solar, and water to produce electric power.

2. CUSTOMER'S OBLIGATIONS

2.1 Customer agrees not to commence interconnected operation of its QF with Company's system, until the installation has been inspected by an authorized Company representative and final written approval is received from Company to commence interconnected operation. Customer shall give reasonable notice to Company when initial startup is to begin. Company shall have the right to have a representative present during initial energizing and testing of Customer's system.

2.2 Customer shall own and be fully responsible for the costs of designing, installing, operating and maintaining:

2.2.1 The QF in accordance with the requirements of all applicable electric codes, laws and governmental agencies having jurisdiction.

2.2.2 Control and protective devices to protect its facilities from abnormal operating conditions such as, but not limited to, electrical overloading, abnormal voltages, and fault currents. Such protective devices shall promptly disconnect the QF from Company's system in the event of a power outage on Company's system.

2.2.3 A gang operated load break disconnect switch, capable of being locked in a visibly open position that will completely isolate the QF from Company's system. Such disconnect switch shall be installed in a place easily accessible to Company's personnel. Company shall have the right to lock open the disconnect switch without notice to Customer when interconnected operation of the QF with Company's system could adversely affect Company's system or endanger life or property.

2.2.4 Interconnection facilities on Customer's premises as may be required to deliver power from Customer's QF to Company's system at the agreed Point Of Interconnection.

2.3 Electric sales to Company must be single or three phase, 60 Hertz, at one standard voltage (12,500; 2400/4160; 480; 277/480; 120/240 or 120/208 volts as may be selected by Customer subject to availability at the premises). Customer's facilities shall also maintain a minimum ninety percent (90%) leading to ninety percent (90%) lagging power factor as measured at the Point Of Interconnection.

2.4 The electrical output of Customer's QF shall not contain harmonic content which may cause disturbances on or damage to Company's electrical system, or other party's systems, such as but not limited to communication systems.

2.5 Customer shall operate and maintain the QF in accordance with those practices and methods, as they are changed from time-to-time, that are commonly used in prudent engineering and electric utility operations and shall operate the QF lawfully and in a safe, dependable and efficient manner.

2.6 Customer shall submit to Company written equipment specifications and detailed plans to Company for the installation and operations of its QF, interconnection facilities, control and protective devices and facilities to accommodate Company's meter(s) for review and advance written approval prior to their actual installation. After Company's approval Customer shall not change or modify equipment specifications, plans, control and protective devices, metering and in general the QF's system configuration. If Customer desires to make such changes or modifications, Customer shall resubmit to Company plans describing said changes or modifications for approval by Company. No such change or modification may be made without the prior written approval of Company.

2.7 In the event it is necessary for Company to install interconnection facilities on its system (including, but not limited to control or protective devices, or any other facilities) in order to receive or continue to receive or to deliver electric power under the terms of the Purchase Agreement, Company shall inform Customer of the cost thereof in advance of incurring the costs of such facilities and Customer shall reimburse Company for the costs incurred by Company in connection with such facilities to the extent that said costs exceed those normally incurred by Company with respect to those customers which it serves who do not have self generation facilities.

2.8 If Customer utilizes the Company's system to facilitate start-up of its QF, the voltage flicker level shall not exceed Company standards.

3. METERING PROVISIONS

3.1 Customer shall provide and install at no expense to Company, and in accordance with Company's service standards, meter sockets and metering cabinets in a suitable location to be determined by Company's representatives.

3.2 Company shall furnish, own, install and maintain all meters that register the sales of power to, and the purchases of energy from Customer. The responsibility for the costs of providing and maintaining the required meters shall be as outlined in the applicable Rate for Purchase, or as specified in the Purchase Agreement.

3.3 The readings of all said meters will be conclusive as to the amount of electric power and energy supplied to the QF and/or purchased by Company unless, upon test, the meters are found to be in error by more than three percent (3%). The expense of any meter test requested by Customer will be borne by Customer unless such test shows the meter(s) to be in error by more than three percent (3%).

4. MUTUAL UNDERSTANDINGS

4.1 Company shall be allowed to install on Customer's premises any instrumentation equipment for research purposes. Such equipment shall be owned, furnished, installed and maintained by Company.

4.2 Company's approvals given pursuant to the Purchase Agreement shall not be construed as any warranty or representation to Customer or any third party regarding the safety, durability, reliability, performance or fitness of Customer's generation and service facilities, its control or protective devices or the design, construction, installation or operation thereof.

4.3 Company (including its employees, agents, and representatives) shall have the right to enter Customer's premises at all reasonable times to (a) inspect Customer's QF, protective devices and to read or test instrumentation equipment that Company may install, provided that as reasonably possible, notice is given to Customer prior to entering its premises; (b) maintain Company equipment relative to the purchase of electric energy from Customer; (c) read or test the meters; and (d) disconnect the QF without notice if, in Company's opinion, a hazardous condition exists and such immediate action is necessary to protect persons, or Company's facilities or other customers' or third parties' property and facilities from damage or interference caused by Customer's QF, or improperly operating protective devices.

4.4 All suitable easements or rights-of-way (required by Company in order to accommodate inter-connection of Company's system with the QF), which are either on premises owned, leased or otherwise controlled by Customer, or upon other property, shall be furnished in Company's name by Customer without cost to or condemnation by Company and in reasonable time to meet the requirements of the Purchase Agreement. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

4.5 Company is not obligated to pay for electric energy or capacity from Customer during any periods when such purchases would result in costs greater than those which Company would otherwise incur had Company generated said energy itself or purchased the energy from another source. Company will give reasonable notice to Customer when such periods exist, so that Customer can discontinue deliveries of energy to Company or elect to continue to sell to Company at a rate, lower than the standard purchase rate, estimated to be the avoided system cost for the period during which such situations exist.

4.6 Company will not install and maintain any lines or equipment on Customer's side of the Point Of Interconnection except its meter (and possibly some research equipment). For the mutual protection of Customer and Company, only authorized employees of Company are permitted to make and energize the interconnection between Company's system and that of Customer's QF. Such employees carry credentials which they will show to Customer upon request.

4.7 The particular rate for purchases applicable to a QF may be dependent on the system configuration of its facilities. Because of the varied and diverse requirements and operating characteristics associated with such facilities, it will be the QF's responsibility to evaluate and determine which system configuration and attendant purchase rate is most appropriate. Company will cooperate with Customer by providing suitable information to enable the Customer to assess the options available; provided, however, that no such information or assistance shall be deemed a representation or warranty by Company with respect to the contents of such information or any particular option available to Customer.

4.8 Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules or at Company's option.

4.9 The interconnection of Company's system with that of Customer will normally be arranged to accept only one type of standard service at one Point Of Interconnection. However, if Customer's QF requires a special type of service (e.g., supplemental, back-up, maintenance or interruptible power in addition to its normal service), or its sales to Company are at a different voltage level than that of its purchases from Company, such service(s) will be provided pursuant to the specific terms outlining such requirements in the Purchase Agreement, applicable rate schedules, and/or other supplemental or special terms and conditions governing such service.

4.10 Each premises owned or controlled by Customer which is served by Company under the Purchase Agreement shall be metered and billed separately. As used herein, the term "premises" shall be deemed to mean a single tract of land owned or controlled by Customer, or separate adjacent or contiguous tracts of land owned or controlled by Customer, operated by it as one tract under the same name or as part of the same business, and not separated by any private or public lands or rights-of-way owned or controlled by third parties.

4.11 All bills rendered for Company services provided to Customer under the provisions of the Purchase Agreement are due and payable upon presentation and are past due fifteen calendar days after mailing of bill. Company reserves the right to suspend or terminate Customer's service for non-payment of service bills past due, for non-payment of interconnection charges, and for non-payment of meter test charges. Past-due service bill amounts, past-due interconnection charges and past-due meter test charges, are subject to an additional charge at the rate of 1-1/2% per month during the period of delinquency.

5. SERVICE RENDERED UNDER SPECIAL AGREEMENT

Purchases will be made from Customer's QF in accordance with the Purchase Agreement, these terms and conditions and any changes required by law, regulation, rule, or order of applicable governmental authority, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of QF's, whose requirements are of unusual size or characteristics, additional or special rate and contract arrangements may be required.

6. REGULATORY AUTHORITY

The rates, terms and other contract provisions governing electric power sold to Customer and the rates or other contract provisions for purchases by Company from Customer are subject to the jurisdiction of the Corporation Commission (ACC) and nothing contained herein shall be construed as affecting or limiting in any way the right of Company (a) to make unilateral filings of changed rates, terms and other contract provisions, which shall be effective when filed, or within a specified number of days thereafter as specified therein, such rates or other contract provisions specified in such filing to be subject to modification if required by a final decision of the ACC, or (b) to unilaterally make application to the ACC for changes in such rates or other contract provisions, following a hearing and decision as permitted by law and the ACC's rules and regulations.

7. INDEMNITY AND INSURANCE

Each Party hereby agrees to indemnify the other Party, its officers, agents, and employees against all loss, damages, expenses and liability to third persons for injury to or death of person or injury to or loss of property, proximately caused by the indemnifying Party's construction, ownership, operation, or maintenance of, or by failure of, any of such Party's works or facilities used in connection with the Purchase Agreement. The indemnifying Party shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party shall also pay all costs and expenses that may be incurred by the other Party in enforcing this indemnity.

8. UNCONTROLLABLE FORCES

No Party shall be considered to be in default in the performance of any of its obligations under the Purchase Agreement (other than obligations of said Party to pay sums to be paid by it hereunder, and other costs and expenses) when a failure of performance shall be due to an uncontrollable force. The term "uncontrollable force" shall be any cause beyond the control of the Party affected, including but not restricted to failure of or threat of failure of facilities, flood, earthquake, tornado, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, strikes, labor or material shortage, sabotage, restraint by court order or public authority, and action or non-action by or in- ability to obtain the necessary authorizations or approvals from any governmental agency or authority, which by exercise of due diligence such Party could not reasonably have been expected to avoid and which by exercise of due diligence it shall be unable to overcome. Nothing contained herein shall be construed so as to require a Party to settle any strike or labor dispute in which it may be involved. Either Party rendered unable to fulfill any of its obligations under this Agreement by reason of an uncontrollable force shall give prompt written notice of such fact to the other Party and shall exercise due diligence to remove such inability with all reasonable dispatch.

9. NOTICES

Any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party to the other may be so given by certified or registered mail, addressed to the Party or personally delivered to the Party at the place designated in the applicable section of the Purchase Agreement. Changes in such designation may be made by notice similarly given.

10. CONFLICTS

10.1 In case of an inconsistency or conflict between any provision of the Purchase Agreement, a rate schedule and/or these terms and conditions, the inconsistency shall be resolved by giving priority to the Purchase Agreement, the rate and then the terms and conditions in said respective order.

11. SUCCESSORS AND ASSIGNS

Purchase Agreement shall be binding upon and for the benefit of the successors and assigns of Customer and Company, but no assignment by Customer shall be binding until accepted in writing by Company (which acceptance shall not be unreasonably withheld) and until the assignee in writing assumes the obligations of Customer under the Agreement.

Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or upgrades to existing facilities. Costs for construction depend on the customer's location, load size, and load characteristics. This schedule establishes the terms and conditions under which Company will extend its facilities to provide new or upgraded facilities.

All extensions are made on the basis of economic feasibility. Construction allowance and revenue basis methodologies are offered below for use in circumstances where feasibility is generally accepted because of the number of extensions made within the construction allowance and dollar limits.

All extensions shall be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and company facilities at the beginning point of an extension also as determined by Company.

The following policy governs the extension of overhead and underground electric facilities, and underground facilities as specified in Section 6, to customers whose requirements are deemed by Company to be usual and reasonable in nature.

1. CONSTRUCTION ALLOWANCE - RESIDENTIAL ONLY

1.1 GENERAL POLICY - Construction allowance extensions may be made only if all of the following conditions exist:

1.1.1 The applicant is a new permanent residential customer or group of new permanent residential customers. Customers specified in Section 4 below are not eligible for this allowance.

1.1.2 The total extension does not exceed a total construction cost of $25,000.

1.1.3 No construction allowance will be permitted beyond the shortest practical route to the nearest practical point of delivery on each customer's site as determined by Company.

1.2 FREE EXTENSIONS - May be made if the conditions specified in Section 1.1 are met and such free extension does not exceed a total construction cost of $3,500.

1.3 EXTENSIONS OVER THE FREE ALLOWANCE

For extensions which meet the conditions specified in Section 1.1 above, and which exceed the free Construction Allowance specified in Section 1.2, Company may extend its facilities up to the maximum allowed in Section 1.1.2 provided the customer or customers will sign an extension agreement and make a non-refundable contribution for the difference between the maximum allowed in Section 1.2 and Company's estimated cost of the extension.

2. REVENUE BASIS - NON-RESIDENTIAL

2.1 GENERAL POLICY - Revenue basis extensions may be made only if all of the following conditions exist:

2.1.1 Applicant is or will be a permanent customer or group of permanent customers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

2.1.2 Such extension does not exceed a total construction cost of $25,000.

2.2 FREE EXTENSIONS

Such extension shall be free to the customer where the conditions specified in Section 2.1 herein are met and the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) multiplied by six (6.0) is equal to or greater than the total construction cost less nonrefundable customer contributions.

2.3 EXTENSIONS OVER THE FREE LIMITS

For extensions which meet the conditions specified in Section 2.1, above, and which exceed the free limits specified in Section 2.1.2, Company may extend its facilities up to a cost limitation of $25,000, provided the customer or customers will sign an extension agreement and advance a sufficient portion of the construction cost so that the remainder satisfies the requirements of Section 2.2. Advances are subject to refund as specified in Section 5.

3. ECONOMIC FEASIBILITY BASIS

3.1 GENERAL POLICY - Extensions may be made on the basis of economic feasibility only if all of the following conditions exist:

3.1.1 The applicant is or will be a permanent customer or group of permanent customers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

3.1.2 The total construction cost exceeds $25,000 except for extensions specified in Sections 4.4 or 7.7.

3.2 FREE EXTENSIONS

Such extensions shall be free to the customer where the conditions specified in Section 3.1 are met and the extension is determined to be economically feasible. "Economic feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the customer.

3.3 EXTENSIONS OVER THE FREE LIMITS

For extensions which meet the conditions specified in Section 3.1, above, Company, after special study and at its option, may extend its facilities to customers who do not satisfy the definition of economic feasibility as specified in Section 3.2, provided such customers sign an extension agreement and advance as much of the construction cost and/or agree to pay such higher special rate (facilities charge) as is required to make the extension economically feasible. Advances are subject to refund as specified in Section 5.

4. OTHER CONDITIONS

4.1 IRRIGATION CUSTOMERS

Customers requiring construction of electric facilities for service to agricultural irrigation pumping will advance the total construction cost. Advances are subject to refund as specified in Section 5.2. Non-agricultural irrigation pumping will be extended as specified in Section 2 or 3.

4.2 TEMPORARY CUSTOMERS

Where a temporary meter or construction is required to provide service to the customer, then the customer, in advance of installation or construction, shall make a non-refundable contribution equal to the cost of installing and removing the facilities required to furnish service, less the salvage value of such facilities. When the use of service is discontinued or agreement for service is terminated, Company may dismantle its facilities and the materials and equipment provided by Company will be salvaged and remain Company property.

4.3 DOUBTFUL PERMANENCY CUSTOMERS

When, in the opinion of Company, permanency of the customer's residence or operation is doubtful, the customer will be required to advance the total construction cost. Advances are subject to refund as specified in Section 5.3.

4.4 REAL ESTATE DEVELOPMENT

Extensions of electric facilities within real estate developments including residential sub divisions, industrial parks, mobile home parks, apartment complexes, planned area developments, etc., may be made in advance of application for service by permanent customers, as specified in Section 3. Anticipated revenue for Residential Real Estate extensions shall be calculated from information provided by the developer.

4.4.1 MOBILE HOME PARKS - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by the utility.

4.4.2 RESIDENTIAL APARTMENT COMPLEXES, CONDOMINIUMS AND OTHER MULTI UNIT RESIDENTIAL BUILDINGS - Company shall refuse service to all new construction and/or expansion of apartment complexes and condominiums unless the construction and/or expansion is individually metered by the utility. Master metering will only be allowed for buildings utilizing centralized heating, ventilation and/or air conditioning system where the contractor can provide an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in R14-2-205 of Corporation Commission's Administrative Rules and Regulations.

5. REFUNDS

5.1 REVENUE AND ECONOMIC FEASIBILITY BASIS REFUNDS

5.1.1 Customer advances over $50.00 are subject to full or partial refund, provided that a survey based on conditions of the extension, not including laterals or extensions from the extension being surveyed as specified in Section 5.1.2 existing at the time of survey, results in an advance lower than the amount actually advanced. Except as provided for in Section 5.3, such surveys shall not be made for customers extended to under the basis specified in Section 4.1, 4.2, or 4.3. A survey will be conducted by Company five (5) years after signing the extension agreement under the extension policy in force at the time of the extension . Upon request, the customer will be entitled to intermediate surveys within the five (5) year period after the end of six (6) months following the date of signing the extension agreement and subsequent surveys at intervals of not less than one (1) year thereafter. Company will refund the difference between the amount advanced and the amount that would have been advanced had the advance been calculated at the time of survey. In no event shall the amount of any refund exceed the amount originally advanced.

5.1.2 Laterals or extensions from an extension being surveyed shall not be considered in the survey when the lateral or extension was extended on the basis "extensions over the free limits" of Sections 2.2 or 3.2, or is not connected directly to the extension being surveyed. In real estate developments extended to under the basis specified in Section 4.4, the survey may include laterals and extensions to serve permanent customers located within the real estate development described in the extension agreement for the extension being surveyed.

5.1.3 In lieu of surveys, Company will determine the refund based on the number of permanent connections to the extension for residential real estate development. In such event, Company shall specify in the extension agreement the amount of refund per permanent customer connection.

5.2 REFUNDS FOR EXTENSIONS TO IRRIGATION CUSTOMERS

Customer advances over $50.00 are subject to refund of twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill, for service to the irrigation pump specified in the agreement for the extension being surveyed, commencing with the date of signing the agreement. In no event shall the amount of any refund exceed the amount originally advanced.

5.3 REFUNDS TO CUSTOMERS OF DOUBTFUL PERMANENCY

Customer advances over $50.00 are subject to full or partial refund pursuant to surveys based on the Revenue or Economic Feasibility Basis as specified in Section 5.1.1. In no event shall the refund exceed twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill for the customer specified in the extension agreement. In no event shall the amount of any refund exceed the amount originally advanced.

5.4. GENERAL REFUND CONDITIONS

5.4.1 Customer advances of $50.00 or less are not subject to refund.

5.4.2 No refund will be made to any customer for an amount more than the unrefunded balance of the customer's advance.

5.4.3 Any unrefunded balance of the customer's advance shall become nonrefundable five (5) years from the date of Company's receipt of the advance.

5.4.4 Company reserves the right to withhold refunds to any customer whose account is delinquent and apply these refund amounts to past due bills.

6. UNDERGROUND CONSTRUCTION

6.1 GENERAL UNDERGROUND CONSTRUCTION POLICY - With respect to all underground installations, Company may install underground facilities only if all of the following conditions are met:

6.1.1 The extension meets feasibility requirements as specified in Sections 1, 2, 3, or 4.

6.1.2 The customer or developer provides all earthwork including, but not limited to, trench, boring or punching, conduits, backfill, compaction, and surface restoration in accordance with Company specifications.

(Company may provide all earthwork and the customer or developer will make a nonrefundable contribution equal to the cost of such work provided by Company.)

6.2 THREE-PHASE UNDERGROUND CONSTRUCTION - Where it is determined that three phase is required to serve the customer, Company may install three-phase facilities if the conditions specified in Section 6.1 are met, and the customer provides the following:

6.2.1 Installation of equipment pads, pull-boxes, manholes, and conduits as required in accordance with Company specifications. In lieu of providing conduits, the customer may provide a nonrefundable contribution equal to the estimated difference in cost between overhead and underground facilities.

6.2.2 A nonrefundable contribution for excess service footage required by the customer equal to the increased estimated cost of installed service lines over what would be required with a maximum 40-foot service at 480 volts and 20-foot service at 120/208 or 240 volts.

6.2.3 Transformer pad and secondary conduits in accordance with Company specifications. (Company may provide pad and conduits, and the customer or developer will make a non-refundable contribution equal to the cost of such work provided by Company.)

7. GENERAL CONDITIONS

7.1 VOLTAGE

The extension will be designed and constructed for operation at standard voltages used by Company in the area in which the extension is located.

7.2 THREE PHASE

Extensions for three phase service can be made under this extension policy where the customer has installed major three phase equipment. Motors with a name-plate rating of 7-1/2 HP or more or single air conditioning units of 6 tons or more or where total horsepower of all connected three phase motors exceeds 12 HP or total load exceeding 100 kVa demand shall qualify for three phase. If the estimated load is less than the above horsepower or connected kVa specifications, Company may, at its option and when requested by the customer, serve three phase and require a nonrefundable contribution equal to the difference in cost between single phase and three phase construction, but in no case less than $100.

7.3 EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be furnished in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

7.4 GRADE MODIFICATIONS

If subsequent to construction of electric distribution lines and services, the final grade established by the customer or developer is changed in such a way as to require relocation of Company facilities or the customer's actions or those of his contractor results in damage to such facilities, the cost of relocation and/or resulting repairs shall be borne by Customer or developer.

7.5 OWNERSHIP

Except for customer-owned facilities, all construction, including that for which customers have made advances and/or contributions, will be owned, operated and maintained by Company.

7.6 MEASUREMENT AND LOCATION

7.6.1 Measurement must be along the proposed route of construction.

7.6.2 Construction will be on public streets, roadways, highways, or easements acceptable to Company.

7.6.3 The extension must be a branch from, the continuation of, or an addition to, one of Company's existing distribution lines.

7.7 UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this policy appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when Customer's estimated load will exceed 3,000 kW, Company will make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contact arrangements as provided for in Section 1.1 of Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

7.8 NON-STANDARD CONSTRUCTION

Company's construction practices employ contemporary methods and equipment and meet current industry standards. Where extensions of electric facilities require construction that is in any way nonstandard, as determined by Company, or if unusual obstructions are encountered, the customer will make a non- refundable contribution equal to the difference in cost between standard and non-standard construction, in addition to other applicable costs involved.

7.9 ABNORMAL LOADS

Company, at its option, may make extensions to serve certain abnormal loads (such as: transformer-type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics), provided the customer makes a nonrefundable contribution equal to the total cost of such extension, including transformers.

7.10 RELOCATIONS AND/OR CONVERSIONS

7.10.1 Company will relocate or convert its facilities for the customer's convenience or aesthetics, providing the customer makes a nonrefundable contribution equal to the total cost of relocation or conversion.

7.10.2 When the relocation or conversion is in conjunction with added revenue, as determined by Company and is not for the customer's convenience or aesthetics, then the relocation or conversion costs plus the costs to serve will be used to determine the customers advance on the basis specified in Section 2 or 3.

7.11 CHANGING OF MASTER METER TO INDIVIDUAL METER

Company will convert its facilities from master metered system to a permanent individually metered system at the customer's request provided the customer makes a nonrefundable contribution equal to the residual value plus the removal costs less salvage of the master meter
facilities to be removed. The new facilities to serve the individual meters will be extended on basis specified in Section 2 or 3.

7.12 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

Company will rebuild or revamp existing facilities to meet the customer's added load or change in service requirements on the basis specified in Section 2 or 3.

7.13 DESIGN DEPOSIT

Any applicant requesting Company to prepare detailed plans, specifications, or cost estimates may be required to deposit with Company an amount equal to the estimated cost of preparation. Where the applicant authorizes Company to proceed with construction of the extension, the deposit shall be credited to the cost of construction; otherwise the deposit shall be nonrefundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the customer for a line extension upon request.

7.14 CUSTOMER CONSTRUCTION OF COMPANY DISTRIBUTION FACILITIES

The customer may provide construction related services, e.g. engineering, survey, materials and/or labor, associated with new distribution facilities to serve the customer's new or added load, provided the customer meets all of the requirements set forth by Company. All work and/or materials provided by the customer shall comply with Company standards in effect at the time of construction. The customer shall receive written approval from Company prior to performing any construction related services. Company will perform an Economic Feasibility Analysis prior to the approval of any proposed customer provided construction to ensure the proposed scope of work results in mutual benefits to the customer and Company.

7.15 SETTLEMENT OF DISPUTES

Any dispute between the customer or prospective customer and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may, by either party, be referred to the Arizona Corporation Commission or a designated representative or employee thereof for determination.

7.16 INTEREST

All advances made by the customer to Company in aid of construction shall be non-interest bearing.

7.16 EXTENSION AGREEMENTS

All line extensions requiring payment by the customer shall be in writing and signed by both the customer and Company.

7.17 ADDITIONAL PRIMARY FEED

Company will provide an additional primary (alternate) feed as requested by the customer provided the customer pays the added cost for the additional feed as a nonrefundable contribution in aid of construction and pays the applicable rate for the additional feed requested.

~~Application for~~ Provision of electric service from Arizona Public Service Company (Company)~~Company's electric service often involves~~ may require construction of new facilities or upgrades to existing facilities. ~~for various distances and costs depending~~ Costs for construction depend on the ~~upon C~~customer's location, load size, and load characteristics. ~~With such variations, it is necessary to establish~~This schedule establishes the terms and conditions under which Company will extend its facilities to provide new or upgraded facilities.

All extensions are made on the basis of economic feasibility. ~~Footage~~ Construction allowance and revenue basis methodologies are offered below for use in circumstances where feasibility is generally accepted because of the number of extensions made within the~~se footage~~ construction allowance and dollar limits.

All extensions shall be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and company facilities at the beginning point of an extension~~, as~~ also as determined by Company.

The following policy governs the extension of overhead and underground electric facilities, and underground facilities as specified in Section 6~~.~~, to customers whose requirements are deemed by Company to be usual and reasonable in nature.

1. ~~FOOTAGE BASIS~~CONSTRUCTION ALLOWANCE - RESIDENTIAL ONLY

1.1 GENERAL POLICY - ~~Footage basis~~Construction allowance extensions may be made only if all of the following conditions exist:

1.1.1 The a~~A~~pplicant ~~will be~~is a new permanent residential c~~C~~ustomer or group of new permanent residential c~~C~~ustomers. Customers specified in Section 4 below are not eligible for this allowance~~basis~~.

1.1.2 The total extension does not exceed a total construction cost of $25,000. ~~2,000 feet per Customer and under no circumstance can the total allowable distance exceed 10,000 feet.~~

1.1.3 No construction allowance~~footage~~ will be permitted beyond the shortest practical route to the nearest practical point of delivery on each c~~C~~ustomer's premises as determined by Company.

~~1.1.4 Such extension does not exceed a total construction cost of $25,000.~~

1.2 FREE EXTENSIONS - May be made if the conditions specified in Section 1.1 are met and such free extension does not exceed a total construction cost of $3,500~~:~~.

~~1.2.1 Such free extension will be limited to a maximum of 1,000 feet per new permanent residential Customer.~~

~~1.2.2 Free allowance for the total extension will be 1,000 feet per Customer regardless of Customer's location along the route of extension.~~

1.3 EXTENSIONS OVER THE FREE ~~DISTANCE~~ALLOWANCE

For extensions which meet the conditions specified in Section 1.1~~,~~ above, and which exceed the free Construction Allowance~~distance~~ specified in Section ~~1.2.1~~1.2, Company may extend its facilities up to the maximum allowed in Section 1.1.2 provided the ~~c~~Customer or ~~c~~Customers will sign an extension agreement and ~~advance the cost of such additional footage. Advances are subject to refund as specified in 5~~make a non-refundable contribution for the difference between the maximum allowed in Section 1.2 and Company's estimated cost of the extension.

2. REVENUE BASIS

2.1 GENERAL POLICY - Revenue basis extensions for non-residential customers may be made only if all of the following conditions exist:

2.1.1 Applicant is or will be a permanent ~~c~~Customer or group of permanent ~~c~~Customers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

2.1.2 Such extension does not exceed a total construction cost of $25,000.

2.2 FREE EXTENSIONS

Such extension shall be free to the ~~c~~Customer where the conditions specified in Section 2.1 herein are met and the estimated annual revenue ~~multiplied by two (2)~~ based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) multiplied by six (6.0) is equal to or greater than the total construction cost less nonrefundable ~~Customer~~ customer contributions.

2.3 EXTENSIONS OVER THE FREE LIMITS

For extensions which meet the conditions specified in Section 2.1~~,~~ above, and which exceed the free limits specified in Section ~~2.2~~2.1.2, Company may extend its facilities up to a cost limitation of $25,000, provided the ~~c~~Customer or ~~c~~Customers will sign an extension agreement and advance a sufficient portion of the construction cost so that the remainder satisfies the requirements of Section 2.2. Advances are subject to refund as specified in Section 5.

3. ECONOMIC FEASIBILITY BASIS

3.1 GENERAL POLICY - ~~Economic feasibility basis E~~Extensions may be made on the basis of economic feasibility only if all of the following conditions exist:

3.1.1 The ~~a~~Applicant is or will be a permanent ~~c~~Customer or group of permanent ~~c~~Customers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

3.1.2 The total construction cost exceeds $25,000 except for extensions specified in Sections 4.4 or 7.7.

3.2 FREE EXTENSIONS

Such extensions shall be free to the ~~c~~Customer where the conditions specified in Section 3.1 are met and the extension is determined to be economically feasible. "Economic feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the ~~c~~Customer.

3.3 EXTENSIONS OVER THE FREE LIMITS

For extensions which meet the conditions specified in Section 3.1, above, Company, after special study and at its option, may extend its facilities to ~~c~~Customers who~~se use~~ does not satisfy the definition of economic feasibility as specified in Section 3.2, provided such ~~c~~Customers sign an extension agreement and advance as much of the construction cost and/or agree to pay such higher special rate (facilities charge) as is required to make the extension economically feasible. Advances are subject to refund as specified in Section 5.

4. OTHER CONDITIONS

4.1 IRRIGATION CUSTOMERS

Customers requiring construction of electric facilities for service to agricultural irrigation pumping will advance the total construction cost~~, which may include a portion of the shared backbone cost from designated irrigation substations, less the first $500 of construction or one slack span for Customers owning their own transformers~~. Advances are subject to refund as specified in Section 5.2. Non-agricultural irrigation pumping will be extended as specified in Section 2 or 3.

4.2 TEMPORARY CUSTOMERS

~~4.2.1~~ Where a temporary meter or construction is required to provide service to the ~~c~~Customer, then the ~~c~~Customer, in advance of installation or construction, shall make a non-refundable contribution equal to the cost of installing and removing the facilities required to furnish service, less the salvage value of such facilities. When the use of service is discontinued or agreement for service is terminated, Company may dismantle its facilities and the materials and equipment provided by Company will be salvaged and remain ~~its~~ Company property.

~~4.2.2 Contributions for temporary service are nonrefundable.~~

4.3 DOUBTFUL PERMANENCY CUSTOMERS

When, in the opinion of Company, permanency of the ~~c~~Customer's residence or operation ~~service~~ is doubtful, the ~~c~~Customer will be required to advance the total construction cost. Advances are subject to refund as specified in Section 5.3.

4.4 REAL ESTATE DEVELOPMENT

Extensions of electric facilities within real estate developments including residential sub- divisions, industrial parks, mobile home parks, apartment complexes, planned area developments, etc., may be made in advance of application for service by permanent ~~c~~Customers, as specified in Section 3. Anticipated revenue for Residential Real Estate extensions ~~under the Revenue Basis or Economic Feasibility Basis shall not be differentiated as between all electric or dual energy service~~shall be calculated from information provided by the developer.

4.4.1 MOBILE HOME PARKS - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by the utility ~~as stated in R14-2-205 of Corporation Commission's Administrative Rules and Regulations~~.

4.4.2 RESIDENTIAL APARTMENT COMPLEXES, CONDOMINIUMS AND OTHER MULTI UNIT RESIDENTIAL BUILDINGS - Company shall refuse service to all new construction and/or expansion of apartment complexes and condominiums unless the construction and/or expansion is individually metered by the utility ~~as stated in R14-2-205 of Corporation Commission's Administrative Rules and Regulations~~. Master metering will only be allowed for buildings utilizing centralized heating, ventilation and/or air conditioning system where the contractor can provide an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in R14-2-205 of Corporation Commission's Administrative Rules and Regulations.

~~4.5 SEASONAL CUSTOMERS~~

~~Extensions of electric facilities to Customer's premises which will be continuously occupied less than 9 months out of each 12 month period may be made only on the basis specified in 2. or 3.~~

5. REFUNDS

5.1 ~~FOOTAGE,~~ REVENUE, AND ECONOMIC FEASIBILITY BASIS REFUNDS

5.1.1 Customer advances ~~of~~ over $50.00 are subject to full or partial refund, provided that a survey based on conditions of the extension, -not including laterals or extensions from the extension being surveyed as specified in Section 5.1.2 existing at the time of survey, results in an advance lower than the amount actually advanced. Except as provided for in Section 5.3, such surveys shall not be made for customers extended to under the basis specified in Section 4.1, 4.2, or 4.3. A survey will be conducted by Company five (5) years after signing the extension agreement under the extension policy in force at the time of the extension ~~and will be made five (5) years after signing the extension agreement~~. Upon request, the ~~c~~Customer will be entitled to intermediate surveys within the five (5) year period after the end of six (6) months following the date of signing the extension agreement and subsequent surveys at intervals of not less than one (1) year thereafter. Company will refund the difference between the amount advanced and the amount that would have been advanced had the advance been calculated at the time of survey. In no event shall the amount of any refund exceed the amount originally advanced.

5.1.2 Laterals or extensions from an extension being surveyed shall not be considered in the survey when the lateral or extension was extended on the basis "extensions over the free limits" of ~~1.~~Sections 2.2~~,~~ or 3.2 herein, ~~or is over 300 feet in length~~ or is not connected directly to the extension being surveyed. In real estate developments extended to under the basis specified in Section 4.4, the survey may include laterals and extensions to serve permanent customers located within the real estate development described in the extension agreement for the extension being surveyed.

5.1.3 In lieu of surveys, Company will determine the refund based on the number of permanent connections to the extension for residential real estate development. In such event, Company shall specify in the extension agreement the amount of refund per permanent c~~C~~ustomer connection.

5.2 REFUNDS FOR EXTENSIONS TO IRRIGATION CUSTOMERS

~~5.2.1~~ Customer advances of over $50.00 are subject to refund of twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill, for service to the irrigation pump specified in the agreement for the extension being surveyed, commencing with the date of signing the agreement. In no event shall the amount of any refund exceed the amount originally advanced.

~~5.2.2 Customer advances on irrigation extensions over one (1) mile in length will be entitled to an additional refund in the event Company extends service to another irrigation Customer (hereinafter called "new applicant") from such extension. Computations for the refund, as specified in the extension agreement, shall be based on the advance applicable to common facilities used to serve Customer and new applicant or applicants and the number of new applicants. The amount of any refund to Customer shall be collected as a portion of the advance from new applicant. For the purpose of determining refunds to the original Customer, no more than one (1) new applicant per whole mile of original extension will be considered.~~

5.3 REFUNDS TO CUSTOMERS OF DOUBTFUL PERMANENCY

Customer advances of over $50.00 are subject to full or partial refund pursuant to surveys based on the Revenue or Economic Feasibility Basis as specified in Section 5.1.1. In no event shall the refund exceed twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill for the c~~C~~ustomer specified in the extension agreement. In no event shall the amount of any refund exceed the amount originally advanced.

5.4. GENERAL REFUND CONDITIONS

5.4.1 Customer advances of $50.00 or less are not subject to refund.

5.4.2 No refund will be made to any c~~C~~ustomer for an amount more than the unrefunded balance of the c~~C~~ustomer's advance.

5.4.3 Any unrefunded balance of the c~~C~~ustomer's advance shall become nonrefundable five (5) years from the date of Company's receipt of the advance.

5.4.4 Company reserves the right to withhold refunds to any c~~C~~ustomer whose account is delinquent and apply these refund amounts to past due bills.

6. UNDERGROUND CONSTRUCTION

6.1 GENERAL UNDERGROUND CONSTRUCTION POLICY - With respect to all underground installations, Company may install underground facilities only if all of the following conditions are met:

6.1.1 The extension meets ~~normal overhead~~ feasibility requirements as specified in Sections 1~~.~~, 2~~.~~, 3~~.~~, or 4.

6.1.2 The c~~C~~ustomer or developer provides all earthwork including, but not limited to, trench, boring or punching, conduits, backfill, compaction, and surface restoration in accordance with Company specifications.

(Company may provide all earthwork and Customer or developer will make a nonrefundable contribution equal to the cost of such work provided by Company.)

~~6.1.3 If armored cable or special cable covering is required, Customer or developer will make a nonrefundable contribution equal to the additional cost of such cable or covering.~~

6.2 THREE-PHASE UNDERGROUND CONSTRUCTION - Where it is determined that three phase is required to serve the c~~C~~ustomer, Company may install three-phase facilities if the conditions specified in Section 6.1 are met, and the c~~C~~ustomer provides the following:

6.2.1 ~~A nonrefundable contribution per primary circuit foot equal to the estimated difference in cost between overhead and underground facilities~~Installation of equipment pads, pull-boxes, manholes, and conduits as required in accordance with Company specifications. In lieu of providing conduits, the customer may provide a nonrefundable contribution equal to the estimated difference in cost between overhead and underground facilities.~~.~~

6.2.2 A nonrefundable contribution for excess service footage required by the c~~C~~ustomer equal to the increased estimated cost of installed service lines over what would be required with a maximum 40-foot service at 480 volts and 20-foot service at 120/208 or 240 volts.

6.2.3 Transformer pad and secondary conduits in accordance with Company specifications. (Company may provide pad and conduits, and the c~~C~~ustomer or developer will make a non-refundable contribution equal to the cost of such work provided by Company.)

~~6.3 NETWORK AREA~~

~~In that portion of Company's service area where the standard service is 277/480 volts from a designated underground network system, Customers who qualify for network service may be supplied standard underground service without extra charge; however, the conditions specified in 6.1 must be met and Customer will be required to make a nonrefundable contribution equal to the cost of the transformer vault where it is used primarily for Customer's benefit.~~

7. GENERAL CONDITIONS

7.1 VOLTAGE

The extension ~~must~~ will be designed and constructed for operation at standard voltages used by Company in the area in which the extension is located.

7.2 THREE PHASE

Extensions for ~~3~~three- phase service can be made under this extension policy where the ~~C~~customer has installed major three~~3~~- phase equipment. ~~Equipment~~ Motors with a name-plate rating of 7-1/2 HP or more or single air conditioning units of 6 tons or more or where total ~~HP~~ horsepower of all connected ~~3~~three- phase motors exceeds 12 HP or total load exceeding 100 ~~KVA~~ kVa demand shall qualify for ~~3~~three- phase. If the estimated load is less than the above ~~HP~~ horsepower or connected ~~KVA~~ kVa specifications~~s installed~~, Company may, at its option~~,~~ and when requested by the ~~C~~customer, serve ~~3~~three- phase and require a nonrefundable contribution equal to the difference in cost between ~~1~~-single phase and ~~3~~three- phase construction, but in no case less than $100.

7.3 EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the ~~C~~customer or developer, or other property required for the extension, shall be furnished in Company's name by the ~~C~~customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

7.4 GRADE MODIFICATIONS

If subsequent to construction of electric distribution lines and services, the final grade established by the ~~C~~customer or developer is changed in such a way as to require relocation of Company facilities or the customer's actions or those of his contractor results in damage to such facilities, the cost of relocation and/or resulting repairs shall be borne by Customer or developer.

7.5 OWNERSHIP

Except for ~~C~~customer-owned facilities, all construction, including that for which ~~C~~customers have made advances and/or contributions, will be owned, operated and maintained by Company.

7.6 MEASUREMENT AND LOCATION

7.6.1 Measurement must be along the proposed route of construction.

7.6.2 Construction ~~is to~~will be on public streets, roadways, highways, or easements acceptable to Company.

7.6.3 The extension must be a branch from, the continuation of, or an addition to, one of Company's existing distribution lines.

7.7 UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this policy appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when ~~in case~~ Customer's ~~requirements~~ estimated load will exceed ~~2,000 kw~~3,000 kW, Company will make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contact arrangements as provided for in Section 1.1 of Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

7.8 NON-STANDARD CONSTRUCTION

Company's construction practices employ contemporary methods and equipment and meet current industry standards. Where extensions of electric facilities require construction that is in any way non-standard, as determined by Company, or if unusual obstructions are encountered, the c~~C~~ustomer will make a non~~-~~refundable contribution equal to the difference in cost between standard and non-standard construction, in addition to other applicable costs involved.

~~Company maintains current construction standards and endeavors to keep abreast of all modern methods and techniques of construction.~~

7.9 ABNORMAL LOADS

Company, at its option, may make extensions to serve certain abnormal loads (such as: transformer-type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics), provided the c~~C~~ustomer makes a nonrefundable contribution equal to the total cost of such extension, including transformers.

7.10 RELOCATIONS AND/OR CONVERSIONS

7.10.1 Company will relocate or convert its facilities for the c~~C~~ustomer's convenience or aesthetics, providing the c~~C~~ustomer makes a nonrefundable contribution equal to the total cost of relocation or conversion.

7.10.2 When the relocation or conversion is in conjunction with added revenue, as determined by Company and is not for the c~~C~~ustomer's convenience or aesthetics, then the relocation or con~~-~~version costs plus the costs to serve will be used to determine the c~~C~~ustomers advance on the basis specified in Section 2~~.~~ or 3.

7.11 CHANGING OF MASTER METER TO INDIVIDUAL METER

Company will convert its facilities from master metered system to a permanent individually metered system at the c~~C~~ustomer's request provided the c~~C~~ustomer makes a nonrefundable contribution equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended on basis specified in Section 2~~.~~ or 3.

7.12 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

Company will rebuild or revamp existing facilities to meet the c~~C~~ustomer's added load or change in service requirements on the basis specified in Sections 2~~.~~ or 3.

7.13 DESIGN DEPOSIT

Any applicant requesting Company to prepare detailed plans, specifications, or cost estimates may be required to deposit with Company an amount equal to the estimated cost of preparation. Where the applicant authorizes Company to proceed with construction of the extension, the deposit shall be credited to the cost of construction; otherwise the deposit shall be nonrefundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the c~~C~~ustomer for a line extension upon request.

7.14 CUSTOMER CONSTRUCTION OF COMPANY DISTRIBUTION FACILITIES

The customer may provide construction related services, e.g. engineering, survey, materials and/or labor, associated with new distribution facilities to serve the customer's new or added load, provided the customer meets all of the requirements set forth by Company. All work and/or materials provided by the customer shall comply with Company standards in effect at the time of construction. The customer shall receive written approval from Company prior to performing any construction related services. Company will perform an Economic Feasibility Analysis prior to the approval of any proposed customer provided construction to ensure the proposed scope of work results in mutual benefits to the customer and Company.

7.~~14~~15 SETTLEMENT OF DISPUTES

Any dispute between the c~~C~~ustomer or prospective c~~C~~ustomer and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may, by either party, be referred to the Arizona Corporation Commission or a designated representative or employee thereof~~,~~ for determination.

7.~~15~~16 INTEREST

All advances made by the c~~C~~ustomer to Company in aid of construction shall be non-interest bearing.

7.16 EXTENSION AGREEMENTS

All line extensions requiring payment by the ~~c~~customer shall be in writing and signed by both the ~~c~~customer and Company.

7.17 ADDITIONAL PRIMARY FEED

Company will provide an additional primary (alternate) feed as requested by the customer provided the customer pays the added cost for the additional feed as a nonrefundable contribution in aid of construction and pays the applicable rate for the additional feed requested.

SCHEDULE 4
TOTALIZED METERING OF MULTIPLE SERVICE ENTRANCE SECTIONS AT A SINGLE SITE FOR STANDARD OFFER AND DIRECT ACCESS SERVICE

Arizona Public Service Company (Company) customers at a single site whose load requires multiple points of delivery through multiple service entrance sections (SESs) may be metered and billed from a single meter through Adjacent Totalized Metering or Remote Totalized Metering as specified in this schedule.

Totalized Metering (Adjacent or Remote) is the measurement for billing purposes on the appropriate rate, through one meter, of the simultaneous demands and energy of a customer who receives electric service at more than one SES at a single site.

A. Totalized metering will either be Adjacent or Remote and shall be permitted only if conditions 1 through 7 are all satisfied.

1. The customer's facilities must be located on adjacent and contiguous sites not separated by private or public property or right-of-way and must be operated as one integral unit under the same name and as a part of the same business or residence (these conditions must be met to be considered a single site, as specified in Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service, Section 4.1.1) ; and

2. Power will generally be delivered at no less than 277/480 volt (nominal), three phase, four wire or 120/240 volt (nominal) single phase three wire; and

3. Three phase and single phase service entrance sections can not be combined for totalizing purposes; and

4. For Standard Offer customers, totalized metering must be accomplished by a physical wire interconnection of metering information with the customer providing conduit between the SES'; for Direct Access customers the customer's Electric Service Provider may provide electronically totalized demand and energy reads in compliance with Company's Schedule 10, Terms and Conditions for Direct Access; and

5. The customer shall provide vault or transformer space, which meets Company specifications, on the customer's property at no cost to Company; and

6. If the customer operates an electric generation unit on the premise, totalized metering will be permitted when the customer complies with all of Company's requirements for interconnection, pays all costs for any additional special metering required to accommodate such service from totalized service sections, and takes service on an applicable rate schedule for interconnected customer owned generation; and

7. Written approval by Company's authorized representative is required before totalized metering may be implemented.

B. Adjacent Totalized Metering will apply when conditions A.1-A.7 and the following conditions are met:

1. The customer's <u>total</u> load to be totalized requires a National Electrical Code (NEC) service entrance size of over 3,000 amps three phase or 800 amps single phase; and

2. Company requires that load be split and served from multiple SESs; and

3. The customer must locate SESs to be totalized within 10 feet of each other.

There will be no additional charge to the customer's monthly bill for Adjacent Totalized Metering.

C. Remote Totalized Metering will apply when conditions A.1-A.7 are met, multiple SESs are separated from one another by more than 10 feet, and the following conditions are met:

1. Each of the customer's service entrance sections to be totalized requires an NEC section size of 3,000 amps three phase or 800 amps single phase or greater; and

2. The customer's total load to be totalized has a minimum demand of 2,000 kVa or 1,500 kW three phase or 100 kVa or 80 kW single phase; and

3. The customer has made a non-refundable contribution for the net additional cost to Company of the meter totalizing connection and equipment.

When the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is equal to or less than the cost to serve a single point of delivery, then no additional monthly charge shall be made to the customer receiving Remote Totalized Metering. However, lower capital investment which results from the customer's contribution, other than the meter costs in C.3 above, shall not be considered.

For customers where the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is greater than the cost to serve at a single point of delivery, then there shall be an additional charge. The additional monthly charge for each delivery point above one shall consist of 1% of the totalized bill, plus $500.00, plus all applicable taxes and adjustments.

D. Removal of Totalized Metering Configuration

In some cases, it may be to the customer's benefit to remove all totalized metering equipment, or remove selected totalized metering equipment from the totalized account. This will be permitted under the following conditions:

1. The customer must submit a written request to Company stating the reason for the removal and the specific equipment to be removed.

2. After removal of the equipment, the customer may not ask for services to be totalized for one (1) year from the removal date. At the end of one (1) year, if the customer does request services to be totalized, the applicable conditions listed above must be met.

3. The customer will be required to make a nonrefundable contribution for the costs associated with the removal of the meter totalizing connection and equipment.

SCHEDULE 4
TOTALIZED METERING OF MULTIPLE SERVICE ENTRANCE SECTIONS AT A SINGLE SITE FOR STANDARD OFFER AND DIRECT ACCESS SERVICE

Arizona Public Service Company (Company) c~~C~~ustomers at a single ~~premise~~ site whose load requires multiple points of delivery through multiple service entrance sections (SES~~'~~s) may be metered and billed from a single meter through Adjacent Totalized Metering or Remote Totalized Metering as specified in this schedule.

Totalized Metering (Adjacent or Remote) is the measurement for billing purposes on the appropriate rate, through one meter, of the simultaneous demands and energy of a customer who receives electric service at more than one SES at a single ~~premise~~site.

A. Totalized metering will either be Adjacent or Remote and shall be permitted only if conditions 1 through 7~~6~~ are all satisfied.

1. The c~~C~~ustomer's facilities must be located on adjacent and contiguous ~~premises~~ sites not separated by private or public property or right-of-way and must be operated as one integral unit under the same name and as a part of the same business or residence (these conditions must be met to be considered a single ~~premise~~site, as specified in Company's Schedule #1, Terms and Conditions for Standard Offer and Direct Access Service, Section 4.1.1) ; and

2. Power will generally be delivered at no less than 277/480 volt (nominal), three-phase, four wire or 120/240 volt (nominal) single phase three wire; and

3. Three phase and single phase service entrance sections can not be combined for totalizing purposes; and

~~3~~4. For Standard Offer customers, totalized metering must be accomplished by a physical wire interconnection of metering information with the c~~C~~ustomer providing conduit between the SESs~~'~~; for Direct Access customers the customer's Electric Service Provider may provide electronically totalized demand and energy reads in compliance with Company's Schedule #10, Terms and Conditions for Direct Access; and

~~4~~5. The c~~C~~ustomer shall provide vault or transformer space, which meets Company specifications, on the c~~C~~ustomer's property at no cost to Company; and

~~5~~6. If the c~~C~~ustomer operates an electric generation unit on the premise, totalized metering will be permitted when the c~~C~~ustomer complies with all of Company's requirements for interconnection, pays all costs for any additional special metering required to accommodate such service from totalized service sections, and takes service on an applicable rate schedule for interconnected c~~C~~ustomer owned generation; and

~~6~~7. Written approval by Company's authorized representative is required before totalized metering may be implemented.

B. Adjacent Totalized Metering will apply when conditions A.1-A.~~6~~7 and the following conditions are met:

1. The c~~C~~ustomer's total load to be totalized requires a National Electrical Code (NEC) service entrance size of over 3,000 amps three phase or 800 amps single phase; and

2. Company requires that load be split and served from multiple ~~SES'~~SESs; and

3. The c~~C~~ustomer must locate ~~SES'~~ SESs to be totalized within 10 feet of each other.

There will be no additional charge to the c~~C~~ustomer's monthly bill for Adjacent Totalized Metering.

C. Remote Totalized Metering will apply when conditions A.1-A.~~6~~7 are met, ~~and~~ multiple ~~SES'~~ SESs are separated from one another by more than 10 feet, and the following conditions are met:

1. Each of the c~~C~~ustomer's service entrance sections to be totalized requires an NEC section size of 3,000 amps three phase or 800 amps single phase or greater; and

2. The c~~C~~ustomer's total load to be totalized has a minimum demand of 2,000 kVa or 1,500 kW three phase or 100 kVa or 80 kW single phase; and

3. The c~~C~~ustomer has made a non-refundable contribution for the net additional cost to Company of the meter totalizing connection and equipment.

When the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is equal to or less than the cost to serve a single point of delivery, then no additional monthly charge shall be made to the c~~C~~ustomer receiving Remote Totalized Metering. However, lower capital investment which results from the c~~C~~ustomer's contribution, other than the meter costs in C.3 above, shall not be considered.

For c~~C~~ustomers where the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is greater than the cost to serve at a single point of delivery, then there shall be an additional charge. The additional monthly charge for each delivery point above one shall consist of 1% of the totalized bill, plus $500.00, plus all applicable taxes and adjustments. ~~For Standard Offer Customers the surcharge of 1% shall be based on their Standard Offer bill. For Direct Access Customers, the surcharge of 1% shall be based on the otherwise applicable Standard Offer rate (either Rate E-32 or E-34). After October 1, 1999 Remote Totalizing with charge will not be available to any Customers not already receiving such service.~~

D. Removal of Totalized Metering Configuration

In some cases, it may be to the customer's benefit to remove all totalized metering equipment, or remove selected totalized metering equipment from the totalized account. This will be permitted under the following conditions:

1. The customer must submit a written request to Company stating the reason for the removal and the specific equipment to be removed.

2. After removal of the equipment, the customer may not ask for services to be totalized for one (1) year from the removal date. At the end of one (1) year, if the customer does request services to be totalized, the applicable conditions listed above must be met.

3. The customer will be required to make a nonrefundable contribution for the costs assicated with the removal of the meter totalizing connection and equipment.

SCHEDULE 5
GUIDELINES FOR ELECTRIC CURTAILMENT

1. Company shall have no liability of obligation for claims arising out of the procedures for curtailment or interruption of electric service effected by it in accordance with such guidelines or such supplemental, amendatory or implementary guidelines or regulations as may hereafter be established and as provided by law.

2. Company shall endeavor to identify any electric customer(s) who might be classified as having either essential or critical loads. In the event that any customer of Company is dissatisfied by the classification of Customer by Company, or with the amount of such customer's load (if any) classifie4d by the Company as critical or essential, the Customer may bring the matter to either the Company or the Commission and request a determination in regard thereto. However, until such redetermination is made by the Commission or the Company, customer's original classification for purposes of electric curtailment under this Schedule shall be unaffected.

3. Company shall endeavor to, as circumstances permit and as further discussed in the Company's detailed Electric Load and Curtailment Plan, to notify County emergency personnel, or similar local authorities, of existing or developing situations involving the curtailment or interruption of APS customers pursuant to this Schedule #5.

4. DEFINITIONS

4.1 Essential Loads – Loads necessary to serve facilities used to protect the heath and safety of the public, such as: hospitals, 911 Centers, national defense installations, sewage facilities and domestic water facilities. Loads necessary to serve 911 Centers, police stations, and fire stations, which do not have independent back-up generation and require APS' electric service for operation of essential emergency equipment.

4.2 Critical Loads – That portion of the electric load of nonresidential customers, which in the event of 100 percent curtailment of service, would cause excessive damage to equipment or material being processed. or where such interruption would create grave hazards to employees or the public.

4.3 Major Use Customers/Others (With Notice) – Those customers having relatively large loads (over 1000 kW) or a substantial number of employees or other special circumstances that make it appropriate to schedule blackouts or curtailments different from typical customers. Customers who qualify as Major Use/Others (With Notice) can take 100 percent curtailment when sufficient notice is provided. These loads will be interrupted after the required notification period. "Sufficient", "required", and "appropriate" notice is that notice that APS, after consultation with the affected customer, has determined will allow the customer to curtail in a safe and efficient manner. Such notice necessarily varies from customer to customer.

4.4 Others (With or Without Notice) – All customers not meeting the above definitions. These customers will be interrupted (with or without notice) if voluntary curtailment measures are not sufficient to alleviate the situation.

5. GUIDELINES TO BE APPLICABLE IN EVENT OF INTERRUPTION OR CURTAILMENT OF ELECTRIC SERVICE BY COMPANY TO ITS CUSTOMERS DUE TO POWER SUPPLY INTERRUPTIONS, FUEL SHORTAGE OR TRANSMISSION EMERGENCY PURSUANT TO CORPORATION COMMISSION RULE R14-2-208, PROVISION OF SERVICE, PARAGRAPH E.

5.1 Operating Procedures Prior to Customer Load Curtailment

5.1.1 The following items shall be pursued concurrently.

5.1.1.1 Reschedule maintenance of transmission components and generating units, where practical.

5.1.1.2 Utilize spinning reserve.

5.1.1.3 Discontinue all non-firm wholesale sales during any period of involuntary curtailment or when an involuntary curtailment is anticipated.

5.1.1.4 Do not enter into any new wholesale sales during any period of involuntary curtailment or when an involuntary curtailment is anticipated.

5.1.1.5 Start all standby units.

5.1.1.6 Contact other utilities and/or agencies for emergency assistance.

5.1.1.7 Invoke emergency and short-term contractual schedules with other utilities and/or agencies.

5.1.1.8 Reduce system voltage, where practical.

5.1.1.9 Reduce non-essential Company uses such as flood lighting, sign lighting, display lighting, office lighting, electric cooling and heating, etc., where practical.

5.1.1.10 Provide information through the media or other appropriate medians to the public which will contain instructions on how customers can assist Company in case of an emergency power outage.

5.2 Voluntary Customer Load Curtailment

5.2.1 Public Appeal

5.2.1.1 An advisory message procedure will be used when Company has advance indications that it will not be able to meet future peak loads. These messages will request voluntary load reduction during specific hours on specific days.

5.2.1.2 An emergency bulletin procedure will be used for instant notification to the public in the event there is no advance indication of a power shortage. These bulletins will request the immediate voluntary cooperation of all customers in reducing electric loads.

5.2.1.2.1 These bulletins will request all customers to reduce the use of all electrically operated equipment and devices, where possible.

5.2.1.2.2 Company will have a prepared statement to read which will give current information on the Power Supply Interruption, Fuels Shortage or Transmission Emergency.

5.3 Contractually Interruptible Load

5.3.1 Company shall invoke contractual interruption provisions to the extent appropriate.

5.3.2 Company shall interrupt non-firm wholesale customer(s) as appropriate.

5.4 Involuntary Customer Load Curtailment

5.4.1 If the load reduction realized from application of the voluntary curtailment procedures is not sufficient to alleviate the power shortage, Company will reduce voltage if and to the extend practical and in accordance with normal applicable electric utility operation standards.

5.4.2 If further load reduction is required, load will be reduced as follows:

5.4.2.1 Circuits not classified with "Major Use/Others With Notice, Critical or Essential" customers will be interrupted on a rotating basis. The frequency and duration of such interruptions will be dependent upon the magnitude and nature of the power shortage. The frequency and duration of such interruptions shall also consider the circumstances of Major Use Customers.

5.4.2.2 Accurate records will be kept to ensure that these circuits are rotated in an equitable and technically feasible manner.

5.4.2.3 Circuits classified as "Major Use/Others" will be interrupted upon the giving of appropriate notice.

5.4.2.4 Customers on circuits which serve critical loads will be required to curtail the non-critical portion of their loads. Thereafter, circuits which serve critical loads will be identified and will not be interrupted unless an area must be dropped to maintain stability of the electric system. However, loads otherwise classifiable as critical may be curtailed if they possess back-up generation sufficient to meet their entire load requirement. If a customer having a critical load refuses or fails to curtail his electric consumption down to the critical load, he shall thereupon not be considered to have a critical load for purposes of this Schedule.

5.4.2.5 Circuits which serve essential loads will be identified and will not interrupted unless an area must be dropped to maintain stability of the electric system. However, loads otherwise classifiable as essential may be curtailed if they possess back-up generation sufficient to meet their entire load requirement.

5.5 Sudden Shortages of Power

In the event that time does not allow for the implementation of the Electric Curtailment Guidelines, Company may resort to its emergency operations procedures, with or without notice.

5.6 Automatic Load Shedding

In the event that there is a major electrical disturbance threatening the interconnected Southwest system with blackout conditions, emergency devices such as under frequency load shedding, transfer tripping, etc., will be utilized to maintain the optimum system stability.

6. ELECTRIC CURTAILMENT OF FIRM WHOLESALE CUSTOMERS

6.1 The term "firm wholesale customer" shall be defined as those APS customers who purchase, on a firm basis, electricity from the Company for purposes of resale.

6.2 In any given instance where a curtailment of wholesale power deliveries is involved, and subject to any required approvals of the Federal Energy Regulatory Commission or contractual provisions to the contrary, Company shall notify its firm wholesale customers, requesting that they curtail electric service to their retail customers during the period that Company's system is affected by power shortages. In the event that Company is unable to obtain the cooperation of a firm wholesale customer, it may seek an order from appropriate governmental authority requiring the firm wholesale customer to accept a reduction of electricity deliveries proportionate to the curtailment being effected on Company's system.

7. ELECTRIC LOAD AND CURTAILMENT PLAN

A detailed electric load and curtailment plan shall be kept on file with the Arizona Corporation Commission. This plan shall contain specific procedures for implementation of the above, along with the name(s) and telephone number(s) of the appropriate Company personnel to contact in the event implementation of the plan becomes necessary. This plan shall be updated at least annually, and it or amendments thereto shall become effective upon submission to the Arizona Corporation Commission.

7.1 Company shall contact the Director, Utilities Division, or their designee, as soon as practical for any curtailment pursuant to this Schedule #5.

SCHEDULE 7
ELECTRIC METER
TESTING AND MAINTENANCE PLAN

General Plan

This schedule establishes a monitoring plan for electric meters in order to ensure an acceptable degree of performance in the registration of the energy consumption of Arizona Public Service Company (Company) customers. Company will file an annual report with the Arizona Corporation Commission summarizing the results of the performance monitoring plan.

Specific Plan

1. Single-Phase Self Contained Meters - Non-Solid State Hybrids and Electro-Mechanical

    1.1 Meters shall be separated into groups having common physical attributes and the average performance of each group will be determined based on the weighted average of the meter's percentage registration at light load (LL) and at full load (FL) giving the full load registration a weight factor of four (4).

    Reference: ANSI C12.1-2001 sections 5.1.4 through 5.1.5.4 or as may be amended by ANSI

    1.2 Analysis of the test results for each group evaluated shall be done in accordance with the statistical formulas outlined in ANSI/ASQC Z1.9 – 1993 Formulas B-3, Tables A-1, A-2 and B-5. The minimum sample size shall be 100 meters when possible.

2. Single Phase Self Contained Meters – Solid State

    Company will monitor performance of these types of meters through the Company Metering and Billing systems.

3. Three Phase Self-Contained Meters - Non-Solid State Hybrids and Electro-Mechanical

    Company shall monitor installations with the following types of meters for accuracy and recalibrate as necessary according to the following schedule:

    3.1 Three-phase meters with surge-proof magnets and without demand registers or pulse initiators: 16 years.

    3.2 Three phase block-interval demand-register-equipped kWh meters with surge-proof magnets: 12 years.

    3.3 Three phase lagged-demand meters: 8 years.

4. Three Phase Self-Contained Meters – Solid State

    Company will monitor performance for these types of meters through the Company Metering and Billing systems.

5. Three Phase Transformer-Rated Meter Installations – Solid State Hybrids and Electro-Mechanical

Company will conduct a periodic testing program whereby three phase transformer-rated meter installations along with their associated equipment shall be inspected and tested for accuracy according to the following schedule:

5.1 Installations with 500 to 1,000 kW load: 4 years.

5.2 Installations with 1001 kW to 2000 kW load: 2 years.

5.3 Installations over 2000 kW load: 1 year.

General Plan

This schedule establishes a monitoring plan for electric meters in order to ensure an acceptable degree of preformance in the registration of the energy consumption of Arizona Public Service Company (Company) customers. ~~To inspect and test electric meters to ensure safe, accurate, and dependable electric service to all customers.~~ Company will file an annual report with the Arizona Corporation Commission summarizing the results of the performance monitoring plan~~meter maintenance and testing program for that year~~.

Specific Plan

1. Single-Phase Self Contained ~~Single Phase KWH~~ Meters~~, Single Phase Block-Interval Demand-Register-Equipped KWH Meters, and Single Phase Lagged-Demand Meters 1/~~ - Non-Solid State Hybrids and Electro-Mechanical

   1.1 Meters shall be separated into groups having common physical attributes and the average performance of each group will be determined based on the weighted average of the meter's percentage registration at light load (LL) and at full load (FL) giving the full load registration a weight factor of four (4).

   Reference: ANSI C12.1-2001 sections 5.1.4 through 5.1.5.4 or as may be amended by ANSI

   1.2 Analysis of the test results for each group evaluated shall be done in accordance with the statistical formulas outlined in ANSI/ASQC Z1.9 – 1993 Formulas B-3, Tables A-1, A-2 and B-5. The minimum sample size shall be 100 meters when possible.

~~Company will conduct a continuous selective meter testing program. Meters shall be separated into homogeneous groups having common physical attributes and the Full Load test point for meters which have been in service shall be evaluated using statistical formulas as follows. The minimum sample shall be 100 meters, and the evaluation shall be made annually.~~

~~Each meter group being evaluated shall meet the following criteria:~~

~~$\bar{X}$ (Bar X) = average error in percent of the sample of meters and is the arithmetic mean of the sample accuracies~~

$$\cancel{\bar{X} = \frac{\sum X}{N}}$$

~~σ (Sigma) = standard deviation of the normal distribution curve, and is a measure of the dispersion of the as found test data about the mean~~

$$\cancel{\sigma = \sqrt{\frac{\sum (X)^2}{N} - \bar{X}^2}}$$

~~Where: $\sum (X)^2$ = summation of the products of numbers of meters and point-by-point squared accuracies~~

~~N = size of sample~~

~~X = individual values of sample accuracies~~

~~The above calculated values shall be substituted in the following equations to determine if the meter group being evaluated meets the following criteria statement: 98% of all meters in each homogeneous group are within + 3% of accurate, with a 95% confidence level.~~

~~High side (maximum) =~~ $\cancel{\overline{X}+2\sigma\overline{X}+2.33\sigma+2\sigma_{\sigma}}$

~~Low side (minimum) =~~ $\cancel{\overline{X}-2\sigma\overline{X}-2.33\sigma-2\sigma_{\sigma}}$

~~Where:~~ $\cancel{\sigma\overline{X}}$ ~~= possible error in~~ $\cancel{\overline{X}}$

$$\cancel{\sigma\overline{X}=\frac{\sigma}{\sqrt{N}}}$$

$\cancel{\sigma_{\sigma}}$ ~~= possible error in~~ $\cancel{\sigma}$

$$\cancel{\sigma_{\sigma}=\frac{\sigma}{\sqrt{2N}}}$$

2. Single Phase Self Contained Meters – Solid State

Company will monitor performance of these types of meters through the Company Metering and Billing systems.

3. ~~All Other~~Three Phase Self-Contained Meters ~~2/~~- Non-Solid State Hybrids and Electro-Mechanical

Company shall monitor installations with the following types of meters for accuracy and recalibrate as necessary according to the following schedule:

~~Shall be tested for accuracy and recalibrated according to the following test schedule.~~

3.1. Three-phase m~~M~~eters with surge-proof magnets and without demand registers or pulse initiators: 16 years.

3.2. Three phase block-interval demand-register-equipped ~~KWH~~ kWh meters with surge-proof magnets: 12 years.

3.3. Three phase lagged-demand meters: 8 years.

4. Three Phase Self-Contained Meters – Solid State

Company will monitor performance for these types of meters through the Company Metering and Billing systems.

5. ~~All~~ Three Phase Transformer-Rated Meters ~~2/~~ Installations – Solid State Hybrids and Electro-Mechanical

Company will conduct a periodic testing program whereby three phase transformer-rated meter installations along with their associated equipment shall be inspected and tested for accuracy according to the following schedule:

~~Shall be tested for accuracy and recalibrated according to the following test schedule.~~

5.1. Installations with ~~With less than 500~~500 to 1,000 k~~K~~W load: 4 years.

5.2. Installations w~~W~~ith ~~500~~ 1001 k~~K~~W to 2000 k~~K~~W load: 2 years.

5.3. Installations ~~With~~ over 2000 k~~K~~W load: 1 year.

~~1/ See ANSI Standard C12-1975, Paragraph 8.1.8.6~~

~~2/ See ANSI Standard C12-1975, Paragraphs 8.1.8.4 and 8.2.3.1~~

SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION OF SPECIALIZED METERING

Arizona Public Service Company (Company) ~~Electric KWH pulses~~ will ~~be~~ provide~~d~~ specialized metering upon customer request, provided ~~by Company if Customer's billing metering equipment is of the type dependent on pulses proportional to KWH to drive the demand meter, and~~ the c~~C~~ustomer agrees to the following conditions:

1. ~~Company will provide electric KWH pulses to Customer who can demonstrate the capability of using such KWH pulses for the purposes of load shaping.~~ The customer must contact their Company Account Representative to request and coordinate the purchase and installation of specialized metering such as KYZ pulse meters, IDR meters, or IDR and KYZ pulse meters. The customer must specify whether a modem will be required.

2. ~~Customer shall submit a plan and wiring diagram for the proposed use of the electric KWH pulses for prior approval by Company's Electric Meter Section.~~ If the customer requests a meter with a modem option, the customer will be required to install communication equipment and connections which shall include a RJ11 or RJ12 jack. A coil of communication cable with either an RJ11 or RJ12 jack is to be provided within five to ten feet of the meter panel location and in such a manner that will provide for ease of attachment of the jack to the meter panel by Company. The phone line must be installed prior to the installation of the meter. The customer must provide Company with a phone number and any other communication access information to the meter(s) prior to Company installation of the meter(s).

3. ~~The Company (through its Electric Meter Section) shall furnish, install and maintain:~~ If a customer requests kWh pulses, Company shall furnish an isolation relay and maintain the output wire and connections from this relay to an approved terminal block to be furnished by the customer. The terminal block shall be located in a lockable junction box mounted adjacent to (but not within) the Company metering compartment and not on the face of the Company metering panel.

   ~~3.1 The isolation relay, in connection with providing KWH pulses, in the billing metering compartment of the service entrance switchboard, and~~

   ~~3.2 The output wires and connections from this relay to an approved terminal block to be furnished by Customer. The terminal block shall be located in a lockable junction box mounted adjacent to (but not within) Company metering compartment and not on the face of Company metering panel.~~

4. ~~Customer shall pay the complete installation cost of the isolation relay and output wiring as set forth above, as a non-refundable contribution.~~ The customer will be required to make a non-refundable contribution in aid of construction to Company for the requested meter(s) installation. The non-refundable contribution amount will be determined at the time of the request as follows:

   4.1 If a meter currently exists on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less the equipment cost of Company's existing meter.

   4.2 If a meter has not been installed on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less 100% of the AUC cost of a Company standard meter.

   4.3 If a specialized meter is existing on a customer's site and the customer requests an upgrade to a different type of meter, the customer will be responsible for 100% of the cost (installation and equipment) associated with the requested meter.

Company will not place an order for a requested meter(s) until payment has been received from the customer. The typical lead time for procurement of meters is six (6) to eight (8) weeks. Once the requested meter(s) have been received, Company will schedule the installation of the meter(s) with the customer or a designated representative.

Company will retain ownership of all meters and Company installed metering equipment.

If a customer makes a nonrefundable contribution for the installation of a specialized meter and then terminates service or requests Company to remove and/or replace the specialized meter, the customer will not be eligible for a refund.

Company will provide general maintenance of the specialized meter; however, in the event the meter should become damaged, obsolete or inoperable, the customer will be responsible for 100% of the replacement cost (installation and equipment) associated with the specialized meter.

Company will not be responsible for the installation, maintenance, or usage fees associated with any phone lines or related communication equipment.

5. Under no circumstances shall the c~~C~~ustomer stop the operation or in any way affect or interfere with the operation of the isolation relay and the related output wiring. The integrity of Company's billing metering equipment within the sealed metering compartment shall be maintained.

6. Company reserves the right to interrupt the specialized metering~~pulse~~ circuit for emergencies or to perform routine or special tests or maintenance on its billing metering equipment, and in so doing assumes no responsibility for affecting the operation of the c~~C~~ustomer's demand control or other equipment. However, Company will make a good faith effort to notify the c~~C~~ustomer prior to any interruption of the ~~pulse~~ specialized metering circuit.

7. The possible failure or malfunction of an isolation relay and subsequent loss of ~~KWH~~ kWh contact closures to the c~~C~~ustomer's control equipment~~,~~ shall in no way be deemed to invalidate or in any way impair the accuracy and readings of Company's meters in establishing the ~~KWH~~ kWh and demand record for billing purposes.

8. The accuracy of the c~~C~~ustomer's ~~impulse totalizer and demand control~~ equipment is entirely the responsibility of the c~~C~~ustomer. Should the c~~C~~ustomer's equipment malfunction, Company will reasonably cooperate with the c~~C~~ustomer to the extent of assuring that no malfunction exists in Company's equipment. Work of this nature will be billed to the c~~C~~ustomer, unless the actual source of the malfunction is found within Company's equipment.

9. If Company provides~~The~~ pulse values in ~~KWH~~ kWh, ~~provided by Company will be those in use by Company's billing metering system.~~ cCustomer's equipment must be capable of readjustment or recalibration to adjust to new contact closure values and rates~~,~~ should it become necessary for Company to adjust the pulse values due to changes in Company's equipment.

10. No circuit for use by the c~~C~~ustomer shall be installed from Company's billing metering potential or current transformer secondaries.

11. Company reserves the right, without assuming any liability or responsibility, to disconnect and/or remove the pulse delivery equipment at any time upon 30 days written notice to the c~~C~~ustomer.

12. Upon request by Company, the c~~C~~ustomer shall make available to Company monthly load analysis information ~~showing the effect of Customer's load regulation~~.

13. References to electric ~~KWH~~ kWh pulses above shall mean isolation relay contact closures only; the c~~C~~ustomer is required to furnish operating voltage service. Isolation relay contacts are rated 5 amps, 28 volts DC or 120 volts AC.

14. The c~~C~~ustomer assumes all responsibility for, and agrees to indemnify and save Company harmless against, all liability, damages, judgments, fines, penalties, claims, charges, costs and fees incurred by Company resulting from the furnishing of ~~electric KWH pulses by Company on Customer's side of the isolation relay~~specialized metering.

15. A waiver at any time by either party, or any default of or breach by the other party or any matter arising in connection with this service, shall not be considered a waiver of any subsequent default or matter.

16. Prior written approval by an authorized Company representative is required before electric ~~KWH~~ kWh pulses service may be implemented.

SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

The following terms and conditions and any changes authorized by law will apply to Arizona Public Service Company (Company), Energy Service Providers (ESPs), and their agents that participate in Direct Access under the Arizona Corporation Commission's (ACC) rules for retail electric competition (A.A.C. R14-2-1601, *et seq.*, referred to herein as the "Rules"). "Direct Access customer" refers to any Company retail customer electing to procure its electricity and any other ACC authorized Competitive Services directly from ESPs as defined in the Rules.

Customer Selections

All Company retail customers shall obtain service under one of two options:

1. Standard Offer Service. With this election, retail customers will receive all services from Company, including metering, meter reading, billing, collection and other consumer information services, at regulated rates authorized by the ACC. Any customer who is eligible for Direct Access who does not elect to procure Competitive Services shall remain on Standard Offer Service. Direct Access customers may also choose to return to Standard Offer Service after having elected Direct Access.

2. Competitive Services (Direct Access). This service election allows customers who are eligible for Direct Access to purchase electric generation and other Competitive services from an ACC certificated ESP. Direct Access customers with single premise demands greater than 20 kW or usage of 100,000 kWh annually will be required to have Interval Metering, as specified in Section 3.6.1. Pursuant to the Rules, and any restrictions herein, the ESP serving these customers will have options available for choosing to offer Meter Services, Meter Reading Services and/or Billing Services on their own behalf (or through a qualified third party), or to have Company provide those services (when permitted by the Rules) as specified within.

1. General Terms

    1.1. Definitions. The definitions of principal terms used in this Schedule shall have the same meaning as ascribed to them in the Rules, unless otherwise expressly stated in this Schedule.

        1.1.1. Customer - Unless otherwise stated, all references to Customer in this agreement refer to Company customers who are eligible for and have elected Direct Access.

        1.1.2. Service Account - Unless otherwise stated, all references to "Service Account" in this agreement shall refer to an installed service, identified by a Universal Node Identifier (UNI).

        1.1.3. Local Arizona Time – All time references in this Schedule are in Local Arizona Time, which is Mountain Standard Time (MST).

2. General Obligations of Company

    2.1. Non-Discrimination

        2.1.1. Company shall discharge its responsibilities under the Rules in a non-discriminatory manner as to providers of all Competitive Services. Unless otherwise authorized by the ACC, the Federal Energy Regulatory Commission ("FERC") or applicable affiliate transactions rules, Company shall not:

2.1.1.1. Represent that its affiliates or customers of its affiliates will receive any different treatment with regard to the provision of Company services than other, unaffiliated services providers as a result of affiliation with Company; or

2.1.1.2. Provide its affiliates, or customers of its affiliates, any preference based on the affiliation including but not limited to terms and conditions of service, information, pricing or timing over non-affiliated suppliers or their customers in the provision of Company services.

2.2. Transmission and Distribution Service

Company will offer transmission and distribution services under applicable tariffs, schedules and contracts for delivery of electric generation to Direct Access customers under the provisions of State law, the terms of the ACC's Rules and Regulations, this Schedule, the ESP Service Acquisition Agreement, applicable tariffs and applicable FERC rules.

3. General Obligations of ESPs

3.1. Timeliness, Due Diligence and Security Requirements

3.1.1. ESPs shall exercise due diligence in meeting their obligations and deadlines under the Rules to facilitate customer choice. ESPs shall make all payments owed to Company in a timely manner.

3.1.2. ESPs shall adhere to all credit, deposit and security requirements specified in the ESP Service Acquisition Agreement and Company tariffs and schedules.

3.2. Arrangements with ESP Customers

ESPs shall be solely responsible for having appropriate contractual or other arrangements with their customers necessary to implement Direct Access. Company shall not be responsible for monitoring, reviewing or enforcing such contracts or arrangements.

3.3. Responsibility for Electric Purchases

ESPs will be responsible for the purchase of their Direct Access customers' electric generation needs and the delivery of such purchases to designated receipt points as set forth on schedules given to the Scheduling Coordinators ("SCs").

3.4. Company Not Liable for ESP Services

To the extent the customer elects to procure services from an ESP, Company has no obligations to the customer with respect to the services provided by the ESP.

3.5. Load Aggregation for Procuring Electric Generation/Split Loads

3.5.1. ESPs may aggregate individually-metered electric loads for procuring competitive electric generation only. Load aggregation shall not be used to compute Company charges or for tariff applicability.

3.5.2. Customers requesting Direct Access Services may not partition the electric loads of a Service Account among electric service options or providers. The entire load of a Service Account must be provided by only one (1) ESP. This provision shall not restrict the use of separate parties for metering and billing services.

3.6. Interval Metering

3.6.1. "Interval Metering" refers to the purchase, installation and maintenance of electricity metering equipment capable of measuring and recording minimum data requirements, including hourly interval data required for Direct Access settlement processes and distribution billing. Interval Metering is required for all customers that elect Direct Access and reach a single site maximum demand in excess of 20 kW one or more times or annual usage of 100,000 kWh or more. Interval Metering is provided by the ESP, at no cost to Company. Interval Metering is optional for those customers with single site maximum demands that are 20 kW or less or annual usage of less than 100,000 kWh.

3.6.2. Company shall determine if Customer meets the requirements for Interval Metering based on historical data, or an estimated calculation of the demand and/or usage for new customers.

3.7. Meter Data Requirements

Minimum meter data requirements consist of data required to bill Company distribution tariffs and determine transmission settlement. Company shall have access to meter data necessary for regulatory purposes or rate-setting purposes pursuant to mutually agreed upon terms with the ESP for such data access.

3.8. Statistical Load Profiles

Pursuant to R14-2-1604(B)(3) Company will offer statistical load profiles in place of Interval Metering, for qualifying Customers to estimate hourly consumption for settlement and scheduling purposes. Statistical load profiles will be applied as authorized by FERC.

3.9 Fees and Other Charges

Direct Access customers shall pay all applicable fees, surcharges, impositions, assessments and taxes on the sale of energy or the provisions of other services as authorized by law. The ESP and Company will each be respectively responsible for paying such fees to the taxing or regulatory agency to the extent it is their obligation to do so. Both the ESP and Company will be responsible for providing the authorized billing agent the information necessary to bill these charges to the customer.

3.10. Liability In Connection With ESP Services

3.10.1. "Damages" shall include all losses, harm, costs and detriment, both direct and indirect, and consequential, suffered by Customer or third parties.

3.10.2. Company shall not be liable for any damages caused by Company conduct in compliance with, or as permitted by, Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service, or as otherwise set forth in Company Schedule #1.

3.10.3. Company shall not be liable for any damages caused to Customer by any ESP, including failure to comply with Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service.

3.10.4. Company shall not be liable for any damages caused by the ESP's failure to perform any commitment to Customer.

3.10.5. An ESP is not a Company agent for any purpose. Company shall not be liable for any damages resulting from acts, omissions, or representations made by an ESP in connection with soliciting customers for Direct Access or rendering Competitive Services.

3.10.6 Under no circumstances shall Company be liable to Customer, ESP (including any entity retained by it to provide competitive services to the customer) or third parties for lost revenues or profits, indirect or consequential damages or punitive or exemplary damages in connection with Direct Access Services. This provision shall not limit remedies otherwise available to customers under Company's schedules and tariffs and applicable laws and regulations.

4. Customer Inquiries and Data Accessibility

4.1 Customer Inquiries – For customers requesting information on Direct Access, Company shall make available the following information:

4.1.1 Materials to consumers about competition and consumer choices.

4.1.2 A list of ESPs that have been issued a Certificate of Convenience and Necessity to offer Competitive Services within Company's service territory. Company will provide the list maintained by the ACC, but Company is under no obligation to assure the accuracy of this list. Reference to any particular ESP or group of ESPs on the list shall not be considered an endorsement or other form of recommendation by Company.

4.2. Access to Customer Usage Data. For Company customers on Standard Offer Service, Company shall provide customer specific usage data to ESP or to Customer, subject to the following provisions:

4.2.1. ESPs may request Customer usage data prior to submission of a Direct Access Service Request ("DASR") by obtaining and submitting to Company the Customer's written authorization on a Customer Information Service Request ("CISR") form. Company may charge for customer usage data.

4.2.2. Company will provide the most recent twelve (12) months of customer usage data or the amount of data available for that Customer if there is less than twelve (12) months of usage history.

4.3 Customer Inquires Concerning Billing Related Issues

4.3.1 Customer inquiries concerning Company charges or services shall be directed to Company.

4.3.2 Customer inquiries concerning ESP charges or services shall be directed to the ESP.

4.4. Customer Inquiries Related to Emergency Situations and Outages

4.4.1. Company shall be responsible for responding to all Standard Offer Service or, in the case of Direct Access customers, distribution service emergency system conditions, outages and safety situation inquiries related to Company's distribution system. Customers contacting an ESP with such inquiries are to be referred directly to Company for resolution. ESPs performing consolidated billing must show Company's emergency telephone number on their bills.

4.4.2. Company may shed or curtail customer load as provided by its ACC-approved tariffs and schedules, or by other ACC rules and regulations.

5. *ESP Service Establishment*

5.1. Before the ESP or its agents can offer Direct Access services in Company distribution service territory they must meet the applicable provisions as listed:

5.1.1. All ESPs must obtain a Certificate of Convenience and Necessity from the ACC which authorizes the ESP to offer Competitive Services in Company's distribution service territory.

5.1.2. All ESPs must register to do business in the State of Arizona and obtain all other licenses and registrations needed as a legal predicate to the ESP's ability to offer Competitive Services in Company's distribution service territory.

5.1.3. Load Serving ESPs must satisfy creditworthiness requirements as specified in the ESP Service Acquisition Agreement if the ESP chooses the ESP Consolidated Billing option. If the ESP chooses Company UDC Consolidated Billing, they must enter into a Customized Billing Services Agreement.

5.1.4 Load Serving ESPs must enter into an ESP Service Acquisition Agreement with Company.

5.1.5. All ESPs must satisfy any applicable ACC electronic data exchange requirements including:

5.1.5.1. The ESP and/or its designated agents must complete to Company's satisfaction all necessary electronic interfaces between the ESP and Company to exchange DASRs and general communications.

5.1.5.2. The ESP or its agent must complete to Company's satisfaction all electronic interfaces between the ESP and Company to exchange meter reading and usage data. This includes communication to and from the Meter Reading Service Provider's (MRSP) server for sharing of meter reading and usage data.

5.1.5.3. The ESP must have the capability to electronically exchange data with Company. Alternative arrangements may be acceptable at Company's option.

5.1.5.4. The ESP and its agents must use Electronic Data Interchange (EDI) using Arizona Standard Formats to exchange billing and remittance data with Company when offering ESP Consolidated Billing or Company UDC Consolidated Billing. The ESP and its agents must use the Arizona Standard Format to exchange meter reading data with Company when providing meter reading services. Alternative arrangements may be allowed at Company's option.

5.1.6. For Company UDC Consolidated Billing or ESP Consolidated Billing options, compliance testing is required. Both parties must demonstrate the ability to perform data exchange functions required by the ACC and the ESP Service Acquisition Agreement. Any change of the billing agent will require a revalidation of the applicable compliance testing. Provided the ESP is acting diligently and in good faith, its failure to complete such compliance testing shall not affect its ability to offer electric generation to Direct Access customers. Dual Company/ESP Billing will be performed until the compliance testing is completed to Company's satisfaction.

5.1.7. Compliance testing will be required for a Load Serving ESP or its MRSP when providing meter reading services to ensure that meter data can be delivered successfully. Any change of the MRSP's system, or any change to the Arizona Standard 867 EDI format, will require a revalidation of the applicable compliance testing.

6. Direct Access Service Request (DASR)

6.1 A DASR is submitted pursuant to the terms and conditions of the Arizona DASR Handbook, the ESP Service Acquisition Agreement and this section, and shall also be used to define the Competitive Services that the ESP will provide the customer.

6.2 ESPs shall have a CC&N from the ACC; shall have entered into an ESP Service Acquisition Agreement with Company, if required, and shall have successfully completed data exchange compliance testing before submitting DASRs.

6.3 The customer's authorized ESP must submit a completed DASR to Company before Customer can be switched from Standard Offer Service or Competitive Service provided by another ESP. The DASR process described herein shall be used for customer Direct Access elections, updates, cancellations, customer-initiated returns to Company Standard Offer Service, or requests for physical disconnection of service and ESP- or customer-initiated termination of an ESP/customer service agreement.

6.4. A separate DASR must be submitted for each service delivery point. Each of the five (5) DASR operation types [Request (RQ), Termination of Service Agreement (TS), Physical Disconnect (PD), Cancel (CL) and Update/Change (UC)] has specific field requirements that must be fully completed before the DASR is submitted to Company. A DASR that does not contain the required field information or is otherwise incomplete may be rejected. In accordance with the provisions of the applicable Service Acquisition Agreement, Company may deny the ESP or customer request for service if the information provided in the DASR is false, incomplete, or inaccurate in any material respect. ESPs filing DASRs are thereby representing that they have their customer's authorization for such transaction.

6.5. Company requires that DASRs be submitted electronically using Electronic Data Interchange (EDI) or Comma Separated Value (CSV) formats through the Company's web site (http://esp.apsc.com).

6.6. DASRs will be handled on a first-come, first-served basis. Each request shall be time and date stamped when received by Company.

6.7. Once the DASR is submitted, the following timeframes will apply:

6.7.1. Company will respond to RQ, TS, CL and UC DASRs within two (2) working days of the time and date stamp. Company will exercise best efforts (no later than five (5) working days) to provide the ESP with a DASR status notification informing them whether the DASR has been accepted, rejected or placed in a pending status awaiting further information. If accepted, the effective switch date will be determined in accordance with Sections 6.8, 6.9, and 6.12 and will be confirmed in the response to the ESP and the former ESP if applicable. If a DASR is rejected, Company shall provide the reasons for the rejection. If a DASR is held pending further information, it shall be rejected if the DASR is not completed with the required information within thirty (30) working days, or a mutually agreed upon date, following the status notification. Company will send written notification to the customer once the RQ DASR has been processed.

6.7.2. When a customer requests electric services to be disconnected, the ESP is responsible for submitting a PD DASR to Company on behalf of the customer, regardless of the Meter Service Provider (MSP).

6.7.2.1. When Company is acting as the MSP, Company shall perform the physical disconnect of the service. The PD DASR must be received by Company at least three (3) working days prior to the requested disconnect date. Company will acknowledge the PD DASR status within two (2) working days of the time and date stamp.

6.7.2.2 When Company is not acting as the MSP, the ESP is responsible for performing the physical disconnect. The ESP shall notify Company by DASR of the date of the physical disconnect. Disconnect reads must be posted to the server within three (3) working days following the disconnection.

6.8. DASRs that do not require a meter exchange must be received by Company at least fifteen (15) calendar days prior to the next scheduled meter read date. The actual meter read date would be the effective switch date. DASRs received less than fifteen (15) calendar days prior to the next scheduled meter read date will be scheduled for switch to Direct Access on the following month's read date.

6.9 DASRs that require a meter exchange will have an effective change date to Direct Access as of the meter exchange date. Notification of meter exchange dates shall be coordinated between the ESP, MSP and Company's Meter Activity Coordinator ("MAC").

6.10. If more than one (1) RQ DASR is received for a service delivery point within a Customer's billing cycle, only the first valid DASR received shall be processed in that period. All subsequent DASRs shall be rejected.

6.11. Upon acceptance of an RQ DASR, a maximum of twelve (12) months of customer usage data, or the available usage for that customer switching from Standard Offer, shall be provided to the ESP. If there is an existing ESP currently serving that customer, that ESP shall be responsible for submitting the customer usage data to the new ESP. In both cases, the customer usage data will be submitted to the appropriate ESP no later than five (5) working days before the scheduled switch date.

6.12. Customers returning to Company Standard Offer service must contact their ESP. The ESP shall be responsible for submitting the DASR on behalf of the customer.

6.13. ESPs requesting to return a Direct Access customer to Company Standard Offer service shall submit a TS DASR and shall be responsible for the continued provision of the customer's electric supply service, metering, and billing services until the effective change date.

6.14. Customers requesting to return to Company Standard Offer service are subject to the same timing requirements as used to establish Direct Access Service.

6.15. Company may assess a fee for processing DASRs. All fees are payable to Company within fifteen (15) calendar days after the invoice date. All unpaid fees received after this date will be assessed applicable late fees pursuant to Schedule 1. If an ESP fails to pay these fees within thirty (30) days after the due date, Company may suspend accepting DASRs from the ESP unless a deposit sufficient to cover the fees due is currently available or until such time as the fees are paid. If an ESP is late in paying fees, a deposit or an additional deposit may be required from the ESP.

6.16. A customer moving to new premises may retain or start Direct Access immediately. The customer must first contact Company to establish a Service Account. The customer will be provided the necessary information that will enable its ESP to submit a DASR. The same timing requirements apply as set forth in Section 6.8 and 6.9.

6.17. Billing and metering option changes are requested through a UC DASR and cannot be changed more than once per billing cycle.

6.18. Company shall not hold the ESP responsible for any customer unpaid billing charges prior to the customer's switch to Direct Access. Unpaid billing charges shall not delay the processing of DASRs and shall remain the customer's responsibility to pay Company. Company's Schedule 1 applies in the event of customer non-payment, which includes the possible disconnection of distribution services. Company shall not accept any DASRs submitted for customers who have been terminated for nonpayment and have not yet been reinstated. Disconnection by Company of a delinquent customer shall not make Company liable to the ESP or third-parties for the customer's disconnection.

6.19 Company shall not accept DASRs that specify a switch date of more than sixty (60) calendar days from the date the DASR is submitted.

7. Billing Service Options and Obligations

7.1 ESPs may select among the following billing options:

7.1.1 COMPANY UDC CONSOLIDATED BILLING

7.1.2 ESP CONSOLIDATED BILLING

7.1.3 DUAL COMPANY/ESP BILLING

7.2 COMPANY UDC CONSOLIDATED BILLING

7.2.1 The customer's authorized ESP sends its bill-ready data to Company, and Company sends a consolidated bill containing both Company and ESP charges to the Customer.

7.2.2 Company Obligations:

7.2.2.1 Company shall bill the ESP charges and send the bill either by mail or electronic means to the customer. Company is not responsible for computing or determining the accuracy of the ESP charges. Company is not required to estimate ESP charges if the expected bill ready data is not received nor is Company required to delay Company billing. Billing rendered on behalf of the ESP by Company shall comply with A.A.C. R14-2-1612.

7.2.2.2 Company bills shall include in Customer's bill a detailed total of ESP charges and applicable taxes, assessments and billed fees, the ESP's name and telephone number, and other information provided by the ESP.

7.2.2.3 If Company processes Customer payments on behalf of the ESP, the ESP shall receive payment for its charges as specified in Section 7.7.

7.2.3 ESP Obligations

7.2.3.1 Once a billing election is in place as specified in the ESP Service Acquisition Agreement, the ESP may offer Company UDC Consolidated Billing services to Direct Access customers pursuant to the terms and conditions of the applicable ACC approved tariff.

7.2.3.2. The ESP shall submit the necessary billing information to facilitate billing services under this billing option by Service Account, according to Company's meter reading schedule, and pursuant to the applicable tariff. Timing of billing submittals is provided for in Section 7.2.4 below.

7.2.4 Timing Requirements

7.2.4.1. Bills under this option will be rendered once a month. Nothing contained in this Schedule shall limit Company's ability to render bills more frequently consistent with Company's existing practices. However, if Company renders bills more frequently than once a month, ESP charges need only to be calculated based on monthly billing periods.

7.2.4.2. Except as provided in Section 7.2.4.1, Company shall require that all ESP and Company charges be based on the same billing period data.

7.2.4.3. ESP charges for normal monthly customer billing and any adjustments for prior months' metering or billing errors must be received by Company in EDI "810" format no later than 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date. If billing charges have not been received from the ESP by this deadline, Company will render a bill for Company charges only. The ESP must wait until the next billing cycle, unless there is a mutual agreement for Company to send an interim bill. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. An interim bill issued pursuant to this Section may also include a message that Company charges were previously billed.

7.2.4.4. ESP charges for a Physical Disconnect Final Bill must be received by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If final billing charges have not been received from the ESP by this date, Company will render the customer's final bill for Company charges only, without the ESP's final charges. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. The ESP must send the final charges to Company. Company will produce and send a separate bill for the final billing charges.

7.2.5. Restrictions

Company UDC Consolidated Billing shall be an option for individual customer bills only, not an aggregated group of customers. Nothing in this Section precludes each individual customer in an aggregated group, however, from receiving the customer's individual bills under Company UDC Consolidated Billing.

7.3. ESP CONSOLIDATED BILLING

7.3.1 Company calculates and sends its bill-ready data to the ESP. The ESP in turn sends a consolidated bill to its customer. The ESP shall be obligated to provide the customer detailed Company charges to the extent that the ESP receives such detail from Company. The ESP is not responsible for the accuracy of Company charges.

7.3.2 Company Obligations:

7.3.2.1 Company shall calculate all its charges once per month based on existing Company billing cycles and provide these to the ESP to be included on the ESP consolidated bill or as otherwise specified. Company and the ESP may mutually agree to alternative options for the calculation of Company charges.

7.3.2.2 Company shall provide the ESP with sufficient detail of its charges, including any adjustments for prior months' metering and billing error, by EDI "810" format. Company charges that are not transmitted to the ESP by 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date need not be included in the ESP's bill. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges unless there is a mutual agreement to have the ESP send an interim bill to the customer including Company charges. The ESP will include a message on the bill stating that Company charges are forthcoming.

7.3.2.3 For a Physical Disconnect Final Bill, Company will provide the ESP with Company's final bill charges by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges. The ESP shall include a message on the bill stating that Company charges are forthcoming. Company will send the final bill charges to the ESP, and the ESP will produce and deliver a separate bill for Company charges.

7.3.3 ESP Obligations:

7.3.3.1 Once an ESP Service Acquisition Agreement is entered into, including an appropriate billing election, and all other applicable prerequisites are met, the ESP may offer consolidated billing services to Direct Access customers they serve.

7.3.3.2 The ESP bill shall include any billing-related details of Company charges. Company charges may be printed with the ESP bill or electronically transmitted. Billing rendered on behalf of Company by the ESP shall comply with A.A.C. R14-2-1612.

7.3.3.3 Other than including the billing data provided by Company on the customer's bill, the ESP has no obligations regarding the accuracy of Company charges or for disputes related to these charges. Disputed charges shall be handled according to ACC procedures.

7.3.3.4 The ESP shall process customer payments and handle collection responsibilities. Under this billing option, the ESP must pay all charges due to Company and not disputed by the customer as specified in Section 7.7.2.1.

7.3.3.5 Subject to the limitations of this Section and with the written consent of the Customer, the ESP may offer customers customized billing cycles or payment plans which permit the Customer to pay the ESP for Company charges in different amounts than Company charges to the ESP for any given billing period. Such plans shall not, however, affect in any manner the obligation of the ESP to pay all Company charges in full. Should Customer select an optional payment plan, all Company charges must be billed in accordance with A.A.C. R14-2-210(G).

7.3.4 Timing Requirements

ESPs may render bills more or less frequently than once a month. However, Company shall continue to bill the ESP each billing cycle period for the amounts due by the customer for that billing month.

7.4 DUAL COMPANY/ESP BILLING

Company and the ESP each separately bill the customer directly for services provided by them. The billing method is the sole responsibility of Company and the ESP. Company and the ESP shall process only the customer payments relating to their respective charges.

7.5 Billing Information and Inserts

7.5.1 All customers, including Direct Access customers, shall receive mandated legal, safety and other notices equally in accordance with A.A.C. R14-2-204 (B). If the ESP is providing consolidated billing, Company shall make available one (1) copy of these notices to the ESP for distribution to customers or, at the ESP's request, in electronic format to the ESP for production and communication to electronically billed Customers. If Company is providing Consolidated billing services, Company shall continue to provide these notices.

7.5.2 Under Company UDC Consolidated Billing, ESP bill inserts may be included pursuant to the applicable Company tariff.

7.6 Billing Adjustments for Meter and Billing Error

7.6.1 Meter and Billing Error

7.6.1.1 The MSP (including the ESP or Company if providing such services) shall resolve any meter errors and must notify the ESP and Company, as applicable, so any billing adjustments can be made. All other affected parties, including the appropriate Scheduling Coordinator, shall be notified by the ESP.

7.6.1.2 A billing error is the incorrect billing of Customer's energy or demand. If the MSP, MRSP, ESP or Company becomes aware of a potential billing error, the party discovering the billing error shall contact the ESP and Company, as applicable, to investigate the error. If it is determined that there is in fact a billing error, the ESP and Company will make any necessary adjustments and notify all other affected parties in a timely manner.

7.6.1.3 Company UDC Consolidated Billing

7.6.1.3.1 Company shall be responsible for notifying Customer and adjusting the bill for its charges to the extent those charges were affected by the meter or billing error.

7.6.1.3.2 The ESP shall be responsible for any recalculation of the ESP charges. Following the receipt of the recalculated charges from the ESP, the charges or credits will be applied to Customer's next normal monthly bill, unless there is mutual agreement to have Company send an interim bill to the Customer including the ESP's charges.

7.6.1.4 ESP Consolidated Billing

7.6.1.4.1 The ESP shall be responsible for notifying the Customer and adjusting the bill for ESP charges to the extent those charges were affected by the meter or billing error. The Customer shall be solely responsible for obtaining refunds of ESP electric generation overcharges from its current and prior ESPs, as appropriate.

7.6.1.4.2 Company shall transmit its adjusted charges and any refunds to the ESP with Customer's next normal monthly bill. The ESP shall apply the charges to Customer's next normal monthly bill, unless there is a mutual agreement to have the ESP send an interim bill to Customer including Company charges.

7.6.1.5 Dual Company/ESP Billing

7.6.1.5.1 Company and the ESP shall be separately responsible for notifying Customer and adjusting its respective bill for their charges.

7.7 Payment and Collection Terms

7.7.1 Company UDC Consolidated Billing

7.7.1.1 Company shall remit payments to the ESP for the total ESP charges collected from Customer within three (3) working days after Customer's payment is received. Company is not required to pay amounts owed to the ESP for ESP charges billed but not received by Company.

7.7.1.2 Customer is obligated to pay Company for all undisputed Company and ESP charges consistent with existing tariffs and other contractual arrangements for service between the ESP and the customer.

7.7.1.3 The ESP is responsible for all collections related to the ESP services on the Customer's bill, including, but not limited to, security deposits and late charges unless otherwise agreed upon in the customized billing services agreement between ESP and Company.

7.7.1.4 Payment for any Company charges for Consolidated Billing is due in full from the ESP within fifteen (15) calendar days of the date Company charges are rendered to the ESP. Any payment not received within this time frame will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2 ESP Consolidated Billing

7.7.2.1 Payment is due in full from the ESP within fifteen (15) calendar days after the date Company's charges are rendered to the ESP. The ESP shall pay all undisputed Company charges regardless of whether Customer has paid the ESP. All payments received after fifteen (15) calendar days will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2.2 Company shall be responsible for any follow-up inquiries with the ESP if there is question concerning the payment amount.

7.7.2.3 Company has no payment obligations to the ESP for Customer payments under ESP Consolidated Billing services.

7.7.3 Dual Company/ESP Billing

Company and the ESP are separately responsible for collection of Customer payment for their respective charges.

7.8 Late or Partial Payments and Unpaid Bills

7.8.1 Company UDC Consolidated Billing

7.8.1.1 Company shall not be responsible for ESP's Customer collections, collecting the unpaid balance of ESP charges from Customers, sending notices informing Customers of unpaid ESP balances, or taking any action to recover the unpaid amounts owed the ESP. The ESP shall assume any collection obligations and/or late charge assessments for late or unpaid balances related to ESP charges under this billing option.

7.8.1.2 All Customer payments shall be applied first to unpaid balances identified as Company charges until such balances are paid in full, then applied to ESP charges. A Customer may dispute charges as provided by A.A.C. R14-2-212, but a Customer will not otherwise have the right to direct partial payments between Company and the ESP.

7.8.1.3 ACC rules shall apply to late or non-payment of all Company customer charges. Undisputed Company delinquent balances owed on a customer account shall be considered late and subject to Company late payment procedures.

7.8.2 ESP Consolidated Billing

The ESP shall be responsible for collecting both unpaid ESP and Company charges, sending notices informing Customers of unpaid ESP and Company balances, and taking appropriate actions to recover the amounts owed. Company shall not assume any collection obligations under this billing option and ESP is liable to Company for all undisputed payments owed Company.

7.8.3 Dual Company/ESP Billing

Company and the ESP are responsible for collecting their respective unpaid balances, sending notices to Customers informing them of the unpaid balance, and taking appropriate actions to recover their respective unpaid balances. Customer disputes with ESP charges must be directed to the ESP and Customer disputes with Company charges must be directed to Company.

7.9 Service Disconnects and Reconnects

In accordance with ACC rules, Company has the right to disconnect electric service to the Customer for a variety of reasons, including, but not limited to, the non-payment of Company's final bills or any past due charges by Customer, or evidence of safety violations, energy theft, or fraud, by Customer. The following provides for service disconnects and reconnects.

7.9.1 Company shall notify Customer and Customer's ESP of Company's intent to disconnect electric service for the non-payment of Company charges prior to disconnecting electric service to the Customer. Company shall further notify the ESP at the time Customer has been disconnected. To the extent authorized by the ACC, a service charge shall be imposed on Customer if a field call is performed to disconnect electric service.

7.9.2 Company shall reconnect electric service for a fee when the criteria for reconnection have been met to Company's satisfaction. Company shall notify the ESP of a Customer's reconnection.

7.9.3 Company shall not disconnect electric service to Customer for the non-payment of ESP charges by Customer. In the event of non-payment of ESP charges by Customer, the ESP may submit a DASR requesting termination of the service agreement and request return to Company Standard Offer Service. Company will then advise the Customer that they will be placed on Company Standard Offer Service unless a DASR is received from another ESP on their behalf.

7.10. Involuntary Service Changes

7.10.1. A Customer may have its service of electricity, billing, or metering from an ESP changed to another provider, including Company, involuntarily in the following circumstances:

7.10.1.1. The ACC has decertified the ESP or the ESP otherwise receives an ACC order that prohibits the ESP from serving the customer.

7.10.1.2 The ESP, including its agents, has materially failed to meet its obligations under the terms of its ESP Service Acquisition Agreement with Company (including applicable tariffs and schedules) so as to constitute an Event of Default under the terms of the ESP Service Acquisition Agreement, and Company exercises its contractual right to terminate the ESP Service Acquisition Agreement.

7.10.1.3 The ESP has materially failed to meet its obligations under the terms of the ESP Service Acquisition Agreement (including applicable tariffs and schedules) so as to constitute an Event of Default and Company exercises a contractual right to change billing options.

7.10.1.4 The ESP ceases to perform by failing to provide schedules through a Scheduling Coordinator whenever such schedules are required, or the ESP fails to have a Service Acquisition Agreement in place with a Scheduling Coordinator.

7.10.1.5. The Customer fails to meet its Direct Access requirements and obligations under the ACC rules and Company tariffs and schedules.

7.10.2. Change of Service Election in Exigent Circumstances

In the event Company finds that an ESP or the Customer has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company elects to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3) and the failure constitutes an emergency (defined as posing a substantial threat to the reliability of the electric system or to public health and safety), or the failure relates to ESP's sale of unscheduled energy, Company may initiate a change in the Customer's service election, or terminate an ESP's ability to offer certain services under Direct Access. In such case, Company shall initiate the change or termination by preparing a DASR, but the change or termination may be made immediately notwithstanding the applicable DASR processing times set forth in this Schedule. Company shall provide such notice and opportunity to remedy the problem if there are reasonable circumstances prevailing. Additionally, Company shall notify the ACC of the circumstances that required the change or the termination and the resulting action taken by Company. The ESP and/or Customer shall have the right to seek an order from the ACC restoring the customer's service election and/or the ESP's ability to offer services. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to Customer other than as provided in Section 4.4.2 .

7.10.3. Change in Service Election Absent Exigent Circumstances

7.10.3.1. In the event Company finds that an ESP has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company seeks to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3), and the failure does not constitute an emergency (as defined in Section 7.10.2) or involve an ESP's unauthorized energy use, Company shall notify the ESP and the ACC of such finding in writing stating the following:

7.10.3.1.1. The nature of the alleged failure;

7.10.3.1.2. The actions necessary to remedy the failure;

7.10.3.1.3. The name, address and telephone number of a contact person at the Company authorized to discuss resolution of the failure.

7.10.3.2. The ESP shall have thirty (30) calendar days from receipt of such notice to remedy the alleged failure or reach an agreement with Company regarding the alleged failure. If the failure is not remedied and no agreement is reached between Company and the ESP following this thirty (30) day period, Company may initiate the DASR process set forth in this Schedule to accomplish its remedy and shall notify the customers of such remedy. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to the customer other than as provided in Section 4.4.2.

7.10.4. Termination of ESP Consolidated Billing

7.10.4.1. Company may terminate ESP Consolidated Billing under the following circumstances:

7.10.4.1.1. The Company shall notify affected Customers that ESP Consolidated Billing services will be terminated, and the Company may switch affected Customers to Dual Company/ESP billing as promptly as possible if any of the following occur:

7.10.4.1.1.1 Company finds that the information provided by the ESP in the ESP Service Acquisition Agreement is materially false, incomplete, or inaccurate.

7.10.4.1.1.2 The ESP attempts to avoid payment of Company charges.

7.10.4.1.1.3 The ESP files for bankruptcy.

7.10.4.1.1.4 The ESP fails to have an involuntary bankruptcy proceeding filed against the ESP dismissed within sixty (60) calendar days.

7.10.4.1.1.5 The ESP admits insolvency.

7.10.4.1.1.6 The ESP makes a general assignment for the benefit of creditors.

7.10.4.1.1.7 The ESP is unable to pay its debts as they mature.

7.10.4.1.1.8 The ESP has a trustee or receiver appointed over all, or a substantial portion, of its assets.

7.10.4.1.2. If the ESP fails to pay Company (or dispute payment pursuant to the procedures set forth in this Schedule) the full amount of all Company charges and fees by the applicable due date, Company shall notify the ESP of the past due amount within two (2) working days of the applicable past due date. If the ESP incurs late charges on more than two (2) occasions or fails to pay overdue amounts including late charges within five (5) working days of the receipt of notice by Company, Company may notify the ESP's customers and the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.

7.10.4.1.3. If the ESP fails to comply within thirty (30) calendar days of the receipt of notice from Company of any additional credit, security or deposit requirements set forth in Sections 5.1.3 and 7.11, Company may notify the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.

7.10.4.2. Upon termination of ESP Consolidated Billing pursuant to Section 7.10.4, Company may deliver a separate bill for all Company charges which were not previously billed by the ESP.

7.10.4.3 Company may reinstate the ESP's eligibility to engage in ESP Consolidated Billing upon a reasonable showing by the ESP that the problems causing the revocation of ESP Consolidated Billing have been cured, including payment of any late charges, reestablishing credit requirements in compliance with Sections 5.1.4 and 7.11, and payment to Company of all costs associated with changing ESP customers' billing elections to and from dual billing.

7.10.4.4 In the event Company terminates ESP Consolidated Billing, Company will return any security posted by the ESP pursuant to the ESP Service Acquisition Agreement.

7.10.5. Termination of Company UDC Consolidated Billing

7.10.5.1. Company may terminate Company UDC Consolidated Billing and revert to Dual Billing upon providing thirty (30) calendar days notice to an ESP if ESP fails to pay Company charges in connection with Company UDC Consolidated Billing or otherwise fails to comply with its obligations under Section 7.2.

7.10.5.2 Company may terminate Consolidated Billing upon providing thirty (30) days notice to an ESP if Company cancels or changes the tariff governing Company UDC Consolidated Billing.

7.10.6. Upon termination of ESP Direct Access services pursuant to Section 7.10, the provision of the affected service(s) shall be assumed by another eligible ESP from which the Customer elects to obtain the affected service(s). Absent an election by Customer, Company shall provide such services, until such time that Customer makes an election.

7.10.7. Company shall not use involuntary service changes in an anticompetitive or discriminatory manner.

7.11. ESP Security Deposits

7.11.1. Company may, at its discretion, require cash security deposits from any ESP that has on more than one occasion failed to pay Company charges or ACC-approved Direct Access charges within the established time frame, such as DASR fees, meter or billing error or service fees, and other fees applicable to an ESP through Schedule 10 and Company's other tariffs and schedules.

7.11.2. The amount of the security deposit required shall not exceed two and one-half times the estimated maximum monthly bill to the ESP for such charges, and a separate security deposit may be required for separate categories of ESP or Direct Access charges.

7.11.3. Security deposits required pursuant to Section 7.11 shall be in the form of a cash deposit accruing interest as specified in Section 2.7.4 of Company Schedule 1. Company shall issue the ESP a nonnegotiable receipt for the amount of the deposit.

7.11.4. Company may refuse to accept DASRs from, or provide other Company services to, an ESP that fails to comply within thirty (30) calendar days to a demand that the ESP establish a security deposit pursuant to Section 7.11.

8. Meter Services

8.1 Under Direct Access, ESPs may offer certain metering services for Direct Access implementation, including meter ownership, MSP and MSRP services.

8.2 Company has the right to offer the following meter services:

8.2.1 Metering and Meter Reading for Residential Load-Profiled Customers

8.2.2 Services as authorized by the ACC.

8.2.3 Company reserves the right to perform meter disconnects, regardless of meter ownership, in cases of potential safety hazards or non-payment for Company charges.

8.3 A Load Serving ESP may sub-contract Metering or Meter Reading Services to a certificated third party. If the ESP sub-contracts any of the components of these services to a third party, the ESP shall, for the purposes of this Schedule, remain responsible for the services.

8.4 Load Serving ESPs providing Metering or Meter Reading Services to Direct Access customers either on their own or through a third party assume full responsibility for meeting the applicable meter and communication standards, as well as assuming responsibility for the safe installation and operation of the meter and any personal injuries and damage caused to customer or Company property by the meter or its installation. This liability will lie with the ESP regardless of whether the ESP or its subcontractors perform the work.

8.5 Meter Specifications

8.5.1 The Director of Utilities Division of the ACC has determined the following specifications and standards shall apply to competitive metering where applicable (see Performance Metering Specifications and Standards document):

8.5.2 Metering standards (American National Standards Institute):

ANSI C12.1	Code for Electricity Metering
ANSI C12.6	Marketing & Arrangement of Terminals for Phase Shifting Devices used in Metering
ANSI C12.7	Watt-hour Meter Socket
ANSI C12.10	Electromechanical Watt-hour Meters
ANSI C12.13	Electronic TOU Registers for Electricity Meters
ANSI C12.18	Type 2 Optical Port
ANSI C12.20	0.2% & 0.5% Accuracy Class Meters
ANSI C37.90	Surge Withstand Test
ANSI 57.13	Instrument Transformers (All CTs & PTs)
ANSI Z1.4	Sampling Procedures and Tables for Inspection
ANSI Z1.9	Sampling Procedures and Tables for Inspection

8.5.3 EEI Electricity Metering Handbook

8.5.4 Electric Utilities Service Equipment Requirements Committee (EUSERC)

8.5.5 NEC & Local Requirements by jurisdictions

8.5.6 Company's Electric Service Requirements Manual (ESRM)

8.5.7 National Electrical Safety Code (NESC)

8.5.8 ESPs or their contractors providing competitive metering services shall also comply with such other specifications or standards determined to be applicable or appropriate by the ACC's Director of Utilities Division.

8.6 Meter Conformity

8.6.1 All Direct Access meters shall have a visual kWh display and must have a physical interface to enable on-site interrogation of all stored meter data. All meters installed must support the Company's rate schedules.

8.6.2 If Company is providing MRSP functions for the ESP, pursuant to the Rules, meters must be compatible with Company's meter reading system.

8.6.3 No meter or associated metering equipment shall be set or allowed to remain in service if it is determined that the meter or its associated equipment did not meet approved specifications, as set forth in Company's ESRM, or is in violation of any code listed in Section 8.5.

8.7 Meter Testing

8.7.1 If a manufacturer's sealed meter has not previously been set and the meter was tested within the last twelve (12) months, the meter shall be deemed in compliance with ACC standards without additional testing.

8.7.2 Any meter removed from service shall be processed according to the following table prior to its re-installation:

METER TYPE	REMOVAL REASON	ACTION REQUIRED
1 Ph kWh Electro-Mechanical	Routine	Meter Inspection
1 Ph kWh Electro-Mechanical	Trouble	Meter Test
1 Ph kWh Hybrid or Solid State	Routine	Meter Test
1 Ph TOU (all)	Trouble	Meter Test
3 Ph Meters (all)	All	Meter Test
1 Ph or 3 Ph IDR Meters	All	Meter Test

8.7.3 Meter tests are to be conducted in accordance with ANSI C12.1 recommended testing standards.

8.7.4 Records on meter testing shall be maintained by the MSP and provided to the requesting parties within three (3) working days of such a request for such records. The latest meter test record shall be kept as long as the meter is in service.

8.8 Meter Test Requests

Pursuant to A.A.C. R14-209(F), either party may request that the other party perform a meter test, in which instance the requesting party is entitled to witness the test if it so chooses. The requesting party shall be notified of the test date and written test results from the testing party. If the meter is found to be within ACC-approved standards, the requesting party shall reimburse the other party for all costs incurred in the process of testing the meter (per ACC approved tariffs). The MSP shall take reasonable measures to detect meter error. The MSP shall notify Company as soon as it becomes aware of any meter that is not operating in compliance with ACC performance specifications. The MSP shall make any repairs or changes required to correct the error. ESPs and Company shall use a form approved by the ACC Process Standardization Working Group (PSWG) to initiate and respond to such action.

8.9 Meter Identification

8.9.1 The ESP or its agent shall install a Company provided unique number on each meter. Company will provide the unique numbers printed on stickers in blocks of up to 1,000 numbers. These stickers must be readily visible from the front of the meter. The number assigned to that meter shall remain solely with that meter while in use in Company's service territory.

8.9.2 When an ESP installs either its own meter or a customer owned meter, the ring or lock ring must be secured with a blue seal that is imprinted with the name and/or logo of the ESP or their agent.

8.10 Installation of metering equipment

8.10.1 All metering equipment shall be installed according to all applicable ACC requirements and Company's Electric Service Requirements Manual.

8.10.2 An ESP or its agent must be authorized by Company to remove a Company owned meter. The Existing Meter Information (EMI) form will be sent to the ESP and MSP within five (5) working days within receiving the DASR acceptance notification indicating a pending meter exchange. When the MSP intends to remove a Company meter, Company must receive a Meter Data Communication Request (MDCR) format at least five (5) working days prior to the exchange. Upon completion of the meter exchange, the MSP will return the Meter Installation/Removal Notification (MIRN) form to Company by the end of business, three (3) working days from the day of the exchange.

8.10.3 The ESP or its agent shall inform Company of all meter activity, such as meter installations or exchanges, via the Meter Activity Coordination (MAC) Form within the time frames specified above. If final meter reads are not provided to Company, are inaccurate, or otherwise result in Company not being able to render accurate final bills to customers pursuant to ACC Rules and Regulations, the ESP shall be responsible for any unbilled, disputed, or unrecoverable amounts and applicable late charges.

8.10.4 The ESP or its agent shall return the existing meter to Company at one of Company's designated locations identified in the meter drop off list within fifteen (15) working days after its removal, or be charged the cost of the meter and metering equipment and /or any other charges per the applicable ACC-approved tariff. The ESP or its agent shall be responsible for damage to the meter occurring during shipment.

8.11 On-Site Inspections/Site Meets

8.11.1 Company may perform on-site inspections of meter installations. The ESP shall be notified if the inspections uncover any material non-compliance by the MSP with the approved specifications and standards.

8.11.2 For new construction, the party installing the meter shall ensure that the owner/builder has met the construction standards outlined in Company's ESRM, and Company's Transmission and Distribution construction manual, as well as local municipal agency requirements, and any updates, supplements, amendments and other changes that may be made to these manuals and requirements. Company shall perform a preinstallation inspection on all new construction. Local city/county clearances may also be required prior to energizing any new construction.

8.11.3 Company may require a site meet for: the exchange or removal of an IDR meter which requires an optical device to retrieve interval data; the exchange or removal of equipment at an existing totalized metering installation; a restricted access location for which Company forbids key access; cogeneration sites, bi-directional or detented metering sites; or upon request of an ESP or MSP. The ESP and Company's MAC shall coordinate the time of the site meet. If the ESP or MSP miss two (2) site meets, Company may cancel the applicable DASR. Company may charge for a site meet requested by the ESP or MSP, or if the ESP or MSP fails to arrive within thirty (30) minutes of the appointment time, or if the ESP fails to cancel a site meet at least one (1) working day in advance of the appointment time.

8.12 Meter Service Options and Obligations

8.12.1 Meter Ownership shall be limited to Company, an ESP, or the customer. The customer must obtain the meter through Company or an ESP. Although a customer may own the electric meter, maintenance and servicing of the metering equipment shall be limited to Company, the ESP, or the ESP's qualified representative (MSP).

8.12.2 Company shall own the CTs, PTs and associated equipment.

8.12.3 All CT-rated meter installations shall utilize safety test switches, and all self-contained commercial metering shall utilize safety-test blocks as provided in Company's ESRM. During meter exchanges, the ESP or its agent's employees who are certificated to perform the related MSP activities may install, replace or operate Company test switches and operate Company-sealed customer-owned test blocks.

8.13 Installation Options

8.13.1 The ESP is responsible for Direct Access customer meter installation. Company may optionally provide meter installation pursuant to the Rules.

8.13.2 ESPs or their agents must be certificated by the ACC in order to offer MSP services. The policies and procedures described in this Section 8.13 assume that the MSP and their meter installers have ACC certification. ESPs may elect to offer metering services by:

8.13.2.1 Becoming a certificated MSP.

8.13.2.2 Subcontracting with a third party that is a certificated MSP.

8.13.2.3 Subcontracting with Company under the circumstances described in Section 8.2.

8.14 As part of providing metering services, ESPs or their agents shall:

8.14.1 Obtain lock ring keys for meters originally installed by Company or request site meets with Company. Company will issue lock ring keys to certified MSPs upon receipt of a refundable deposit. The deposit will not be refunded if a key is either lost or stolen, and a fee will be applied to replace lost or damaged keys. For more information about the cost of lock rings, standard rings, or lock ring keys, please consult the Company MAC.

8.14.2 If lock rings are used they shall meet Company requirements. If a meter is installed and the readings are obtained from a source other than a physical inspection, a lock ring must be utilized. Lock rings may be purchased from Company.

8.14.3 Provide information to Company on the specifications and other specifics on meters not purchased from or installed by Company.

8.14.4 Allow Company to remove the customer's meter, or schedule a site meet to remove the meter transferring from Direct Access to Standard Offer service. If the ESP allows Company to remove meters, ESP shall coordinate with Company regarding the return of the meters.

8.14.5 Be responsible for obtaining and providing reads from any meter that it installs from the time it is installed to the time it is removed or until meter reading responsibilities are assumed by another ESP or the customer returns to Standard Offer service.

8.14.6 Ensure that ESP and MSP employees working in Company's territory follow ACC and other applicable safety standards.

8.14.7 Company shall notify the ESP immediately and the ESP shall notify Company immediately of any suspected unauthorized energy use when a safety hazard exists. In instances where there is not a safety hazard, each party will notify each other within twenty-four (24) hours. The ESP shall ensure that a lock ring is installed to secure any meter that does not require a monthly local (i.e., manual) meter read. The Parties agree to preserve any evidence of unauthorized energy use. Once unauthorized energy use is suspected, Company, in its sole discretion, may take any or all of the actions permitted under Company's tariffs and schedules and shall notify the ACC of any such action taken.

8.14.8 Take no action to impede Company's safe and unrestricted access to a customer's service entrance.

8.14.9 Glass over any socket when a meter is removed and a new meter is not installed.

8.15 MSRP Services provided as a responsibility of an ESP

Only certificated MRSP's acting on the ESP's behalf in accordance with ACC regulations shall perform MRSP functions. The MRSP for each Direct Access customer will be specified on the DASR received from the ESP. Any changes to Customers MRSP will be updated by the ESP with a "UC" DASR at least ten (10) days prior to the next schedules read date. MSRP obligations and responsibilities are stated in the ACC's Rules and Regulations and include:

8.15.1 Meter data for Direct Access Customers shall be read, validated, edited, and transferred pursuant to Arizona's Validation, Editing, and Estimation Process (VEE). It is the responsibility of the MRSP to comply with this process. In cases where validated data is unavailable for transfer by the posting deadline, it is the responsibility of the MRSP to provide an estimated data file for the entire read cycle until actual meter data is available. At such time as actual data becomes available, a corrected data file shall be posted immediately.

8.15.2 Both Company and the ESP shall have 24-hour/7 days per week access to the MRSP server.

8.15.3 Meter read data shall include beginning and ending reads as well as the validated usage for load-profiled customers. Validated interval data shall be provided for all interval metering customers. Data must be posted to the MRSP server using the Arizona Standard EDI "867" format. Estimated data shall contain applicable reason codes pursuant to the 867 guidelines.

8.15.4 The MRSP shall provide Company with access to meter data at the MRSP server as required to allow the proper performance of billing and settlement.

8.15.5 MRSPs must have a CC&N from the ACC authorizing it to offer MSRP services, and must be certified in Company territory.

8.15.6 MRSPs shall read Customer's meter based on the scheduled read date per Company's Yearly Meter Read Schedule. The billing cycle for each meter shall contain the full period from read date to the following read date. Interval data cycles shall be considered from 00:15 on the read date to 00:00 on the following read date (i.e. 9/1/00 00:15 through 10/1/00 00:00). The first complete interval timestamp shall begin at 00:15 in each cycle. For meter exchanges to Direct Access, the first complete interval through the first read date at 00:00 shall constitute the billing cycle. For meter exchanges back to Standard Offer, every interval shall be included up to the last full interval prior to the exchange. It is the responsibility of the MRSP to provide estimation of any intervals that are necessary to constitute the full billing cycle.

8.15.7 The MRSP shall provide re-reads or read verifies within ten (10) working days of a request by Company or Customer. The requesting party may be charged per the applicable ACC tariff if the original read was not in error.

8.16 Meter Reading Data Obligations

8.16.1 Accuracy for all meters.

8.16.1.1 Meter clocks shall be maintained according to Arizona time within +/- three (3) minutes of the National Time Standard.

8.16.1.2 Meter read date and time shall be accurate.

8.16.1.3 All meter reading data shall be validated with the pursuant to the approved Arizona VEE guidelines.

8.16.2 Timeliness for Validated Meter Reading Data

Pursuant to guidelines established by the Utilities Division Director, one hundred percent (100%) of the validated meter data shall be available by 3:00 p.m. Local Arizona Time (MST) on the third working day after the scheduled read date. If the meter data is not posted, is unavailable, or clearly contains errors by this deadline, the billing determinants including usage (kWh) and demand (kW) may be estimated by Company and the ESP shall be charged an approved charge for this service.

8.16.3 Proof of Operational Ability

Prior to performing MRSP services in Company's distribution service territory, or prior to making any significant change in MRSP service methodology, each MRSP will perform compliance testing to demonstrate its ability to read meters, validate data, edit data, estimate missing data and post validated data in Company-compatible EDI format to the MRSP server. In addition, upon installation of the initial meter on Direct Access accounts in Company's distribution service territory, each MRSP shall prove its ability to read its meters and post validated data in Company-compatible EDI format to the MRSP server. If the MRSP is unsuccessful in its attempts to meet these requirements, all subsequent requests for meter exchanges will be postponed until the MRSP successfully demonstrates its operational ability.

8.16.4 Retention and Format for Meter Reading Data

8.16.4.1 All meter reading data for a Customer shall remain posted on the MRSP server for five (5) working days and will be recoverable for at least three (3) years.

8.16.4.2 Meter reading data posted to the MRSP server shall be stored in Company-compatible EDI format.

8.17 Company performing MSP and MRSP functions:

If Company is eligible to perform Direct Acccss related MSP and MRSP functions as defined in section 8.2, the following restriction applies:

The validated meter read will be posted in EDI format no later than 6 working days following the scheduled read date.

8.18 Non-Conforming Meters, Meter Errors and Meter Reading Errors

8.18.1 Whenever Company, the ESP or its agents becomes aware of any non-conforming meters, erroneous meter services and/or meter reading services that impact billing, it shall promptly notify the other parties and the affected Customer. Bills found to be in error due to non-conforming meters or errors in meter services or meter reading services will be corrected by the appropriate parties.

8.18.2 In cases of meter failure or non-compliance, the ESP or its agents shall have five (5) working days to correct the non-compliance. If the non-compliance is not remedied within five (5) working days, the following actions may apply:

8.18.2.1 A site meeting may be required when services are being performed. The non-compliant party may be charged an ACC-approved tariff for the meeting.

8.18.2.2 Company may repair the defect, and the other party shall be responsible for all related expenses.

8.18.2.3 Company shall adhere to the approved Performance Monitoring Standards and follow the steps outlined to address non-compliance by an MRSP.

8.18.3 Company may refuse to enter into a new ESP Service Acquisition Agreement, or cancel an existing ESP Service Acquisition Agreement pursuant to section 7.10.1.1.2, with any ESP or its agents that has a demonstrated pattern of uncorrected non-compliance as established above. This provision shall not apply if the alleged demonstrated pattern of non-compliance or correction thereof is disputed and is pending before any agency or entity with jurisdiction to resolve the dispute.

SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

The following terms and conditions and any changes authorized by law will apply to ~~APS~~Arizona Public Service Company (Company), Energy Service Providers (ESPs),~~ESPs~~ and their agents that participate in Direct Access under the Arizona Corporations Commission's ("ACC") rules for retail electric competition (A.A.C. R14-2-1601, *et seq.,* referred to herein as the "Rules"). "Direct Access customer" refers to any ~~APS~~ Company retail customer electing to procure its electricity and any other ACC-authorized Competitive Services directly from ESPs as defined in the Rules. ~~ESPs who serve Direct Access customer accounts shall possess a Certificate of Convenience and Necessity, issued by the ACC pursuant to A.A.C. R14-2-1604; enter into an ESP Service Acquisition Agreement with APS and an agreement with an APS-approved and/or Arizona Independent Scheduling Administrator Association ("AISA") approved Scheduling Coordinator; be registered to do business in the State of Arizona; and meet any other applicable certification requirements established by State law and by the appropriate regulatory agencies.~~

Customer Selections

All ~~APS~~ Company retail ~~electric~~ customers shall obtain ~~electric generation and ACC authorized energy~~ services under one of two options:

1. Standard Offer Service ~~(Bundled Service)~~. With this election, retail customers will receive all services from Company, including metering, meter reading, billing, collection and other consumer information services~~,~~ ~~on a bundled basis~~ at regulated rates authorized by the ACC. Any customer ~~that has not chosen Direct Access, and who is eligible for Direct Acess,~~ who is eligible for Direct Access who does not elect to procure Competitive Services shall remain on Standard Offer Service. Direct Access customers may also choose to return to Standard Offer Service after having elected Direct Access. ~~Refer to R14-2-1601 for further definitions.~~

2. Competitive Services (Direct Access). This service election allows customers who are eligible for Direct Access to purchase electric generation and other Competitive ~~Services~~ services from an ACC certificated ESP. Direct Access customers with single premise demands greater than 20 kW or usage of 100,000 kWh annually will be required to have ~~in place~~ Interval Metering, as ~~defined below~~ ~~at no expense to APS.~~ specified in Section 3.6.1. Pursuant to the Rules, and any restrictions herein, the ESP serving these customers will have options available for choosing to offer Meter Services, Meter Reading Services and/-or Billing Services on their own behalf (or through a qualified third party), or to have ~~APS~~the Company provide those services (when permitted by the Rules) as specified within. ~~Meter service options are described in the Sections on Metering Services and Meter Service Options and Obligations in this Schedule #10. Billing options are described in the Sections on Billing Service Options and Obligations in this Schedule #10 and the ESP Service Acquisition Agreement.~~

1. General Terms

1.1. Definitions. The definitions of principal terms used in this Schedule shall have the same meaning as ascribed to them in the Rules, unless otherwise expressly stated in this Schedule.

~~1.1.1.~~ ~~The definitions of principal terms used in this Schedule shall have the same meaning as ascribed to them in the Rules, unless otherwise expressly stated in this Schedule.~~

~~1.1.2.~~ 1.1.1. Customer - Unless otherwise stated, all references to ~~"customer~~Customer" in this agreement refer to ~~APS~~ Company customers who are eligible for and have elected Direct Access.

1.1.~~3~~2. Service Account - Unless otherwise stated, all references to "S~~s~~ervice A~~a~~ccount" in this agreement shall refer to an installed service, identified by a Universal Node Identifier (UNI).

~~1.1.4. First Meter Read Date – Unless otherwise stated, all references to "First Meter Read Date" shall refer to the first working day that meter reads can be obtained for a billing cycle. APS will publish the meter read schedule yearly, by month, subject to change.~~

~~1.1.5. Last Meter Read/First Bill Date – Unless otherwise stated, all references to "Last Meter Read Date/First Bill Date" shall refer to a pre-established working day defined each month for the purpose of producing customer bills. The Last Meter Read/First Bill Date is the first day of the APS bill processing window. The Last Meter Read/First Bill Date will always be at least three (3) days after the First Meter Read Date. APS will publish the meter read schedule yearly, by month, subject to change.~~

1.1.~~6~~3. Local Arizona T~~t~~ime – All time references in this Schedule ~~# 10~~ are in L~~l~~ocal Arizona T~~t~~ime, which is Mountain Standard Time (MST). ~~Arizona does not observe Daylight Savings Time.~~

2. General Obligations of ~~APS~~Company

2.1. Non-Discrimination

2.1.1. ~~APS~~ Company shall discharge its responsibilities under the Rules in a non-discriminatory manner as to providers of all Competitive Services. Unless otherwise authorized by the ACC, the Federal Energy Regulatory Commission ("FERC") or applicable affiliate transactions rules, ~~APS~~ Company shall not:

2.1.1.1. Represent that its affiliates or customers of its affiliates will receive any different treatment with regard to the provision of ~~APS~~ Company services than other, unaffiliated services providers as a result of affiliation with ~~APS~~Company; or

2.1.1.2. Provide its affiliates, or customers of its affiliates, any preference based on the affiliation including but not limited to terms and conditions of service, information, pricing or timing over non-affiliated suppliers or their customers in the provision of ~~APS~~ Company services.

2.2. Transmission and Distribution Service

~~2.2.1. Subject to State law and the terms of the ACC's Rules and Regulations, this Schedule # 10, the ESP Service Acquisition Agreement, applicable tariffs and applicable ACC and FERC rules, and provided the ESP and customer likewise comply therewith,~~ ~~APS~~Company will offer transmission and distribution services under applicable tariffs, schedules and contracts for delivery of electric generation to Direct Access customers~~.~~ under the provisions of State law, the terms of the ACC's Rules and Regulations, this Schedule, the ESP Service Acquisition Agreement, applicable tariffs and applicable FERC rules.

~~2.3. Competitive Transition Charges (CTC)~~

~~2.3.1. Competitive Transition Charges are a means of recovering Stranded Costs from customers who elect Direct Access Service. As a condition for receiving Direct Access Service, these customers will be responsible to APS for all CTC charges (or any other means of recovering stranded costs) as authorized by the Rules and as may be subsequently approved by the ACC.~~

~~2.4. System Benefit Charges (SBC)~~

~~2.4.1. System Benefits Charges are those charges approved by the Commission for recovery of low-income, demand side management, environmental, renewable, nuclear fuel disposal costs and nuclear power plant decommissioning costs and other approved costs from customers that elect Direct Access Service. As a condition for receiving Direct Access Service, these customers will be responsible to pay all System Benefit Charges authorized by the Rules in A.A.C. R14-2-1608 and as may be subsequently approved by the ACC.~~

3. General Obligations of ESPs

3.1. Timeliness, Due Diligence and Security Requirements

3.1.1. ESPs shall exercise due diligence in meeting their obligations and deadlines under the Rules to facilitate customer choice. ESPs shall make all payments owed to ~~APS~~ Company in a timely manner ~~(pursuant to the ACC's requirements, the Rules, the ESP Service Acquisition Agreement the ESP enters into with APS, and APS' tariffs and schedules) and subject to applicable payment dispute provisions described below~~.

3.1.2. ESPs shall adhere to all credit, deposit and security requirements specified in the ESP Service Acquisition Agreement and ~~APS'~~ Company tariffs and schedules.

3.2. Arrangements with ESP Customers

~~3.2.1~~ ESPs shall be solely responsible for having appropriate contractual or other arrangements with their customers necessary to implement Direct Access ~~consistent with all applicable laws, ACC requirements, the Rules and this Schedule # 10~~. ~~APS~~ Company shall not be responsible for monitoring, reviewing or enforcing such contracts or arrangements.

3.3. Responsibility for Electric Purchases

~~3.3.1.~~ ESPs will be responsible for the purchase of their Direct Access customers' electric generation needs and the delivery of such purchases to designated receipt points as set forth on schedules given to the Scheduling Coordinators ("SCs").

3.4. ~~APS~~ Company Not Liable for ESP Services

~~3.4.1~~ To the extent the customer elects to ~~take other~~ procure services from an ESP, ~~APS~~ Company has no obligations to the customer with respect to the services provided by the ESP.

3.5. Load Aggregation for Procuring Electric Generation/Split Loads

3.5.1. ESPs may aggregate individually-metered electric loads for procuring competitive electric generation only. Load aggregation shall not be used to compute ~~APS~~ Company charges or for tariff applicability.

3.5.2. Customers requesting Direct Access Services may not partition the electric loads of a S~~s~~ervice A~~a~~ccount among electric service options or providers. The entire load of a S~~s~~ervice A~~a~~ccount must be provided by only one (1) ESP. This provision shall not restrict the use of separate parties for metering and billing services.

3.6. Interval Metering

3.6.1. "Interval Metering" refers to the purchase, installation and maintenance of electricity metering equipment capable of measuring and recording minimum data requirements, including hourly interval data required for Direct Access settlement processes and distribution billing. Interval Metering is required for all customers that elect Direct Access and ~~have~~ reach a ~~maximum~~ single ~~premise~~ site maximum demand~~s~~ in excess of 20 kW one or more times or annual usage of 100,000 kWh or more~~annually~~. Interval Metering is provided by the ESP, at no cost to Company. Interval Metering is optional for those customers with single site maximum demands that are 20 kW or less ~~demands of 20 kW~~ or annual usage of 100,000 kWh ~~annually or less~~or more.

3.6.2. ~~For new customers without prior demand data, APS shall estimate the demand at the time the customer establishes a distribution service account with APS.~~ ~~APS~~ Company shall determine~~,~~ ~~based on its estimates of the customer's demand,~~ whether if the C~~c~~ustomer meets the requirements for Interval Metering based on historical data, or an estimated calculation of the demand and/or usage for new customers. ~~With the customer's written consent, APS shall provide the customer's ESP with the data upon which the demand estimate was made.~~

3.7. Meter~~ing~~ Data Requirements

~~3.7.1.~~Minimum meter data requirements consist of data required to bill ~~APS~~ Company distribution tariffs and determine transmission settlement. ~~APS~~ Company shall have access to meter data necessary for regulatory purposes or rate-setting purposes pursuant to mutually agreed upon terms with the ESP for such data access.

3.8. Statistical Load Profiles

~~3.8.1 Pursuant to R14-2-1604(B)(3) and R14-2-1603(J)(7) APS~~Company will offer statistical load profiles in place of Interval Metering, for qualifying C~~c~~ustomers to estimate hourly consumption for settlement and scheduling purposes. Statistical load profiles will be applied as authorized by FERC.

3.9 Fees and Other Charges

~~3.9.1.~~ Direct Access customers shall pay all applicable fees, surcharges, impositions, assessments and taxes on the sale of energy or the provisions of other services as authorized by law. The ESP and ~~APS~~ Company will each be respectively responsible for paying such fees to the taxing or regulatory agency to the extent it is their obligation to do so. Both the ESP and ~~APS~~ Company will be responsible for providing the authorized billing agent the information necessary to bill these charges to the customer.

3.10. Liability In Connection With ESP Services

3.10.1. ~~In this section, "damages"~~ "Damages" shall include all losses, harm, costs and detriment, both direct~~,~~ and indirect, and consequential, suffered by ~~the c~~Customer or third parties.

3.10.2. ~~APS~~ Company shall not be liable for any damages caused by ~~APS'~~ Company conduct in compliance with, or as permitted by, ~~APS'~~ Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service, or as otherwise set forth in ~~APS'~~ Company's Schedule #1.

3.10.3. ~~APS~~ Company shall not be liable for any damages caused to ~~the c~~Customer by any ESP, including failure to comply with ~~APS'~~ Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service.

3.10.4. ~~APS~~ Company shall not be liable for any damages caused by the ESP's failure to perform any commitment to ~~the c~~Customer~~, including~~.

3.10.5. An ESP is not ~~an APS~~a Company agent for any purpose. ~~APS~~ Company shall not be liable for any damages resulting from acts, omissions, or representations made by an ESP in connection with soliciting customers for Direct Access or rendering Competitive Services.

3.10.6 Under no circumstances shall ~~APS~~ Company be liable to ~~the c~~Customer, ESP (including any entity retained by it to provide competitive services to the customer) or third parties for lost revenues or profits, indirect or consequential damages or punitive or exemplary damages in connection with Direct Access Services. This provision shall not limit remedies otherwise available to customers under ~~APS'~~ Company's schedules and tariffs and applicable laws and regulations.

4. Customer Inquiries and Data Accessibility

4.1 Customer Inquiries – For customers requesting information on Direct Access, ~~APS~~Company shall make available the following information:

4.1.1 ~~Notification and informational materials~~ Materials to consumers about competition and consumer choices.

4.1.2 A list of ESPs that have been issued a Certificate of Convenience and Necessity to offer Competitive Services within ~~APS'~~ Company's service territory. ~~APS~~ Company will provide the list maintained by the ACC, but ~~APS~~ Company is under no obligation to assure the accuracy of this list. Reference to any particular ESP or group of ESPs on the list shall not be considered an endorsement or other form of recommendation by ~~APS~~Company.

4.2. Access to Customer Usage Data. ~~-~~ For ~~APS~~ Company customers on Standard Offer Service, ~~APS~~ Company shall provide customer specific usage data to ESP s ~~that have an ESP Service Acquisition Agreement in place with APS,~~ or to ~~the~~ Ccustomer, subject to the following provisions:

4.2.1. ESPs may request Ccustomer usage data prior to submission of a Direct Access Service Request ("DASR") by obtaining and submitting to ~~APS~~ Company the Ccustomer's written authorization on a Customer Information Service Request ("CISR") form. ~~APS~~ Company may charge for customer usage data ~~at rates approved by the ACC~~.

4.2.2. ~~APS~~ Company will provide the most recent twelve (12) months of customer usage data or the amount of data available for that Ccustomer if there is less than twelve (12) months of usage history.

4.3 Customer Inquires Concerning Billing Related Issues

4.3.1 Customer inquiries concerning ~~APS~~ Company charges or services shall be directed to ~~APS~~Company.

4.3.2 Customer inquiries concerning ESP charges or services shall be directed to the ESP.

4.4. Customer Inquiries Related to Emergency Situations and Outages

4.4.1. ~~APS~~ Company shall be responsible for responding to all Standard Offer Service or, in the case of Direct Access customers, distribution service emergency system conditions, outages and safety situation inquiries related to ~~APS'~~ Company's distribution system. Customers contacting an ESP with such inquiries are to be referred directly to ~~APS~~ Company for resolution. ESPs performing consolidated billing must show ~~APS'~~ Company's emergency telephone number on their bills ~~for use in emergencies~~.

4.4.2. ~~APS~~ Company may shed or curtail customer load as provided by its ACC- approved tariffs and schedules, or by other ACC rules and regulations.

5. ESP Service Establishment

5.1. ~~An ESP, providing competitive generation, shall satisfy the following requirements~~ Bbefore the ESP or its agents can offer Direct Access services in ~~APS'~~ Company distribution service territory they must meet the applicable provisions as listed:

~~5.1.1. Enter into an ESP Service Acquisition Agreement with APS.~~

5.1.~~2~~1. All ESPs must o~~O~~btain a Certificate of Convenience and Necessity from the ACC which authorizes the ESP to offer Competitive Services ~~to Direct Access customers within~~in ~~APS'~~ Company's distribution service territory.

5.1.~~3~~2. All ESPs must r~~R~~egister to do business in the State of Arizona and obtain all other licenses and registrations needed as a legal predicate to the ESP's ability to offer Competitive Services ~~to Direct Access customers~~ in ~~APS'~~ Company's distribution service territory.

5.1.~~4~~3. Load Serving ESPs must s~~S~~atisfy ~~APS'~~ creditworthiness requirements as specified in the ESP Service Acquisition Agreement if the ESP ~~will offer~~chooses the ESP Consolidated Billing option. If the ESP chooses Company UDC Consolidated Billing, they must enter into a Customized Billing Services Agreement.

5.1.4 Load Serving ESPs must enter into an ESP Service Acquisition Agreement with Company.

5.1.5. All ESPs must s~~S~~atisfy any applicable ACC electronic data exchange requirements including:

5.1.5.1. The ESP and/or its designated agents must ~~successfully~~ complete to Company's satisfaction all necessary electronic interfaces between the ESP and ~~APS~~ Company to exchange DASRs and general communications.

5.1.5.2. The ESP or its agent must ~~successfully~~ complete to Company's satisfaction all electronic interfaces between the ESP and ~~APS~~ Company to exchange meter reading and usage data. This ~~will~~ includes communication to and from the Meter Reading Service Provider's (MRSP) servers for sharing of meter reading and usage data.

5.1.5.3. The ESP must have the capability to electronically exchange data with ~~APS electronically~~Company. Alternative arrangements may be acceptable ~~if mutual agreement is reached between APS and the ESP~~at Company's option.

5.1.5.4. The ESP and its agents must use Electronic Data Interchange (EDI) using Arizona Standard Formats to exchange billing and remittance data with Company when offering ESP Consolidated Billing or Company UDC Consolidated Billing. The ESP and its agents must use the Arizona Standard Format to exchange meter reading data with Company when providing meter reading services. ~~APS will require the ESP and its agents to exchange data with APS using Electronic Data Interchange (EDI), and enter into appropriate agreements as part of the ESP Service Acquisition Agreement, if the ESP or its agents will be offering APS UDC Consolidated Billing, ESP Consolidated Billing, or metering or meter reading services.~~ Alternative arrangements may be allowed at Company's option~~if mutual agreement is reached between APS and the ESP~~.

5.1.6. For ~~the APS~~ Company UDC Consolidated Billing or ESP Consolidated Billing options, compliance testing ~~for EDI transactions will be~~is required. Both parties must demonstrate the ability to perform ~~the EDI~~ data exchange functions required by the ACC and the ESP Service Acquisition Agreement. Any change of the billing agent will require a revalidation of the applicable compliance testing. Provided the ESP is acting diligently and in good faith, its failure to complete such compliance testing shall not affect its ability to offer electric generation to Direct Access customers. Dual ~~APS~~Company/ESP Billing will be performed until the compliance testing is completed to Company's satisfaction.

5.1.7. Compliance testing will be required for ~~Meter Reading Service Providers (MRSP)~~a Load Serving ESP or its MRSP when providing meter reading services to ensure that ~~billing can be completed~~meter data can be delivered successfully. Any change of the MRSP's system, or any change to the Arizona Standard 867 EDI format, will require a revalidation of the applicable compliance testing ~~applicable~~. ~~APS reserves the right to charge the ESP for obtaining or estimating reads at ACC-approved rates until such time as the MRSP has completed successful compliance testing as outlined in Section 8.16.3 of this Schedule # 10.~~

6. Direct Access Service Request (DASR)

6.1 A ~~Direct Access Service Request ("~~DASR~~")~~ is submitted pursuant to the terms and conditions of the Arizona DASR Handbook, the ESP Service Acquisition Agreement and this section, and shall also be used to define the Competitive Services that the ESP will provide the customer.

6.2 ESPs shall have a CC&N from the ACC; shall have entered into an ESP Service Acquisition Agreement with ~~APS~~ Company, if required~~;~~, and shall have successfully completed ~~EDI~~ data exchange compliance testing before submitting DASRs.

6.3 The customer's authorized ESP must submit a completed DASR to ~~APS~~ Company before ~~the~~ ~~c~~Customer can be switched from Standard Offer Service or Competitive Service provided by another ESP. The DASR process described herein shall be used for customer Direct Access elections, updates, cancellations, customer-initiated returns to ~~APS~~ Company Standard Offer Service, or requests for physical disconnection of service and ESP- or customer-initiated termination of an ESP/customer service agreement.

6.4. A separate DASR must be submitted for each service delivery point. Each of the five- (5) DASR operation types [Request (RQ), Termination of Service Agreement (TS), Physical Disconnect (PD), Cancel (CL) and Update/Change (UC)] has specific field requirements that must be fully completed before the DASR is submitted to ~~APS~~Company. A DASR that does not contain the required field information or is otherwise incomplete may be rejected. In accordance with the provisions of the applicable Service Acquisition Agreement, ~~APS~~ Company may deny the ESP or customer request for service if the information provided in the DASR is false, incomplete, or inaccurate in any material respect. ESPs filing ~~RQ~~ DASRs are thereby representing that they have their customer's ~~written~~ authorization for such transaction. ~~ESPs filing all other DASRs are thereby representing that they have their customer's authorization for such transaction.~~

6.5. ~~APS~~ Company ~~may~~ requires that DASRs be submitted electronically using Electronic Data Interchange (EDI) or Comma Separated Value (CSV) formats through the ~~APS~~ Company's web site (http://esp.apsc.com).

6.6. DASRs will be handled on a first-come, first-served basis. Each request shall be time and date stamped when received by ~~APS~~Company.

6.7. Once the DASR is submitted, ~~APS will provide an acknowledgment of its receipt to the ESP or customer within the following timeframes~~the following timeframes will apply:

6.7.1. ~~APS~~ Company will respond to ~~Request~~ (RQ), ~~Termination of Service Agreement (TS)~~, ~~Cancel (CL)~~ and ~~Update/Change~~ (UC) DASRs within two (2) working days of the time and date stamp. ~~APS~~ Company will exercise best efforts~~, within three (3) working days thereafter~~ (~~and~~ no later than five (5) working days ~~thereafter~~)~~,~~ to provide the ESP with a DASR status notification informing them whether the DASR has been accepted, rejected or placed in a pending status awaiting further information. If accepted, the effective switch date will be determined in accordance with Sections 6.8, 6.9, and 6.12 ~~of this Schedule # 10~~, and will be confirmed in the response to the ESP~~,~~ and the former ESP if applicable~~, and through written notification to the customer~~. If a DASR is rejected, ~~APS~~ Company shall provide the reasons for the rejection. If a DASR is held pending further information, it shall be rejected if the DASR is not completed with the required information within thirty (30) working days, or as mutually agreed upon date, following the status notification. Company will send written notification to the customer once the RQ DASR has been processed.

6.7.2. When a customer requests ~~its~~ electric services to be disconnected, the ESP is responsible for submitting a ~~Physical Disconnect~~ (PD) DASR to ~~APS~~Company on behalf of the customer, regardless of ~~who controls the meter, on behalf of the customer~~the Meter Service Provider (MSP).

6.7.2.1. When ~~the control of the meter resides with APS~~Company is acting as the MSP, ~~it~~ Company shall perform the physical disconnect of the service. The "PD" DASR must be received by ~~APS~~ Company at least three (3) working days prior to the requested disconnect date. ~~APS~~ Company will acknowledge the "PD" DASR status within ~~the~~ two (2) working days of the time and date stamp.

6.7.2.2 ~~When the control of the meter resides with the ESP~~When Company is not acting as the MSP, the ESP is responsible for performing the physical disconnect. The ESP shall notify ~~APS~~ Company by DASR of the date of the physical disconnect. Disconnect reads must be posted to the ~~MRSP or~~ ESP server within three (3) working days following the disconnection.

6.8. ~~Pursuant to A.A.C. R14-2-203(D)(4),~~ DASRs ~~for customers~~ that do not require a meter exchange must be received by ~~APS~~ Company at least fifteen (15) calendar days prior to the next scheduled meter read date. The actual meter read date ~~will~~ would be the effective switch date. DASRs received less than fifteen (15) calendar days prior to the next scheduled meter read date will be scheduled for switch to Direct Access on the following month's read date.

6.9 ~~Accepted~~ DASRs that require a meter exchange will have an effective change date to Direct Access ~~with the~~as of the meter exchange date. Notification of meter ~~install~~ exchange dates shall be coordinated between the ESPs, MSPs and ~~APS'~~ Company's Meter Activity Coordinator ("MAC").

6.10. If more than one (1) RQ DASR is received for a service delivery point within a Customer's billing cycle, only the first valid DASR received shall be processed in that period. All subsequent DASRs shall be rejected.

6.11. Upon acceptance of an RQ DASR, a maximum of twelve (12) months of customer usage data, or the available usage for that customer switching from Standard Offer, shall be provided to the ESP. If there is an existing ESP currently serving that customer, that ESP shall be responsible for submitting the customer usage data to the new ESP. In both cases, the customer usage data will be submitted to the appropriate ESP no later than five (5) working days before the scheduled switch date. ~~ESPs filing DASRs will thereby be representing that they have written authorization from the customer to receive the customer usage information.~~

6.12. Customers returning to ~~APS~~ Company Standard Offer service ~~shall follow the same process timing as is used to establish Direct Access service~~must contact their ESP. The ESP shall be responsible for submitting the DASR on behalf of the customer.

6.13. ESPs requesting to return a Direct Access customer to ~~APS~~ Company Standard Offer service shall submit a ~~Termination of Service~~TS DASR and shall be responsible for the continued provision of the customer's electric supply service, metering, and billing services until the effective change date.

6.14. Customers requesting to return to ~~APS'~~ Company Standard Offer service ~~must contact their ESP. The ESP shall be responsible for submitting the appropriate DASR on behalf of the customer~~are subject to the same timing requirements as used to establish Direct Access Service.

6.15. ~~APS~~ Company may assess a ~~charge~~ fee for processing DASRs ~~at a fee approved by the ACC~~. All ~~ACC-approved charges~~fees are payable to ~~APS~~ Company within fifteen (15) calendar days after the invoice date. ~~All charges received~~All unpaid fees received after this date will be assessed applicable late fees pursuant to Schedule #-1. If an ESP fails to pay these ~~charges~~ fees within thirty (30) days after the due date, ~~APS~~ Company may suspend accepting DASRs from the ESP unless a deposit sufficient to cover the ~~charges~~ fees due is currently available or until such time as the ~~charges~~ fees are paid. If an ESP is late in paying ~~changes~~ fees, a deposit or an additional deposit may be required from the ESP.

6.16. A customer moving to new premises may retain or start Direct Access immediately. The customer must first contact ~~APS~~ Company to establish a ~~S~~service ~~A~~account. The customer will be provided the necessary information that will enable its ESP to submit a DASR. The same timing requirements apply as set forth in ~~this~~ Section 6.8 and 6.9 ~~of Schedule #10~~. ~~Customer eligibility requirements set forth in the ACC Rules will apply during the phase-in period (January 1, 1999 though December 31, 2000).~~

6.17. Billing ~~option~~ and metering option changes are requested through a "UC" DASR and cannot be changed more than once per billing cycle.

6.18. ~~APS~~ Company shall not hold the ESP responsible for any customer unpaid billing charges prior to the customer's switch to Direct Access. Unpaid billing charges shall not delay the processing of DASRs and shall remain the customer's responsibility to pay ~~APS~~Company. ~~APS~~ Company's Schedule ~~#~~ 1 applies in the event of customer non-payment, which includes the possible disconnection of distribution services. ~~APS~~ Company shall not accept any DASRs submitted for customers who have been terminated for nonpayment and have not yet been reinstated. Disconnection by ~~APS~~ Company of a delinquent customer shall not make ~~APS~~ Company liable to the ESP or third-parties for the customer's disconnection.

~~6.19. During the phase-in period (January 1, 1999 though December 31, 2000), residential customers will be eligible for Direct Access on a first-come, first-served basis. APS will accept DASRs for up to 3,500 customers per quarter beginning December 1, 1998 or the effective date of this Schedule, whichever is later. The quarter shall be closed once APS has accepted DASRs for the total number of customers eligible in that quarter. APS shall maintain a waiting list of up to 24,500 DASRs after the close of the first quarter. If the waiting list is full, no further DASRs will be accepted. Residential customer eligibility for Direct Access service is not site specific, and a residential customer that moves within APS' distribution service territory after becoming eligible for Direct Access service retains such eligibility. If a residential customer receiving Direct Access service returns to Standard Offer service, that customer must reapply for Direct Access eligibility through the DASR process. APS will periodically update the APS ESP Web Site with eligibility and waiting list status.~~

~~6.20. During the phase-in period (January 1, 1999 though December 31, 2000) ESPs , are required to complete a Direct Access Load Aggregation Submittal form (DALAS) for those customers they choose to aggregate. DALAS forms will be accepted for customers with single premise non-coincident peak demand loads of 40 kW or greater (or greater than 16,500 kWh for one month of the last twelve (12) consecutive months if no demand load data is available) aggregated into a combined load of 1 MW or greater. The DALAS form shall be submitted to APS, at which point APS will review and approve the form, if it is complete and accurate in all material respects and satisfies the requirements for load aggregation. APS will notify the ESP if the DALAS form is valid within three (3) working days. Upon approval by APS, ESPs must submit the DASRs for the service delivery points indicated on the DALAS form within three (3) working days. DASRs received prior to DALAS form approval shall be rejected. DASRs received by APS within the 40 – 999 kW load ranges will be rejected if not participating in an APS-approved load aggregation pool (i.e., complied with the DALAS process set forth in this Section). APS will begin accepting DALAS forms on November 25, 1998 or the effective date of this Schedule, whichever is later.~~

~~6.21. During the phase-in period (January 1, 1999 though December 31, 2000), the number of commercial and industrial customers eligible to participate in Direct Access will be based on the amount of megawatts available for competition under the Rules. For APS, 653 MWs of load is available on a first-come, first-served basis. APS will begin accepting DASRs for eligible customers (customers with a non-coincident demand of 1MW and greater and those approved through the DALAS process) on December 1, 1998, or the effective date of this schedule, whichever is later, until such time that the available load is fulfilled. Eligibility for Direct Access service for commercial and industrial customers during the phase-in period is both customer and site specific. During the phase-in period only, APS shall not accept DASRs that specify a Direct Access switch date of more than sixty (60) calendar days from the date the DASR is submitted to APS.~~

~~6.22. During the phase-in period (January 1, 1999 through December 31, 2000), all residential customers that produce or purchase at least ten percent (10%) of their annual electricity from photovoltaic or solar thermal energy resources that were installed in Arizona after January 1, 1997 shall be eligible for participation in Direct Access. Subject to the 653 MW limitation set forth in Section 6.21, all commercial customers that produce or purchase at least ten percent (10%) of their annual electricity from photovoltaic or solar thermal energy resources that were installed in Arizona after January 1, 1997 shall be eligible for participation in Direct Access. The ESP shall identify customers eligible for Direct Access under this Section. APS may implement processes to verify and track eligibility under this Section.~~

6.19 Company shall not accept DASRs that specify a switch date of more than sixty (60) calendar days from the date the DASR is submitted.

7. Billing Service Options and Obligations

7.1 ~~Subject to availability, and pursuant to the terms in the ESP Service Acquisition Agreement, this Schedule # 10, and applicable tariffs and the restrictions therein,~~ ESPs may select among the following billing options:

7.1.1 ~~APS~~ COMPANY UDC CONSOLIDATED BILLING

7.1.2 ESP CONSOLIDATED BILLING

7.1.3 DUAL ~~APS~~COMPANY/ESP BILLING

7.2 ~~APS~~ COMPANY UDC CONSOLIDATED BILLING

7.2.1 The customer's authorized ESP sends its bill-ready data to ~~APS~~Company, ~~or APS calculates ESP charges,~~ and ~~APS~~ Company sends a consolidated bill containing both ~~APS~~ Company and ESP charges to the ~~c~~Customer. ~~All charges by APS to the ESP for consolidated billing shall be at rates approved by the ACC.~~

7.2.2 ~~APS~~ Company Obligations:

7.2.2.1 ~~If the ESP elects to send bill-ready data, APS~~Company shall ~~include~~ bill the ESP charges and send the bill either by mail or electronic means to the customer. ~~APS~~ Company is not responsible for computing or determining the accuracy of the ESP charges ~~on the bill~~. ~~APS~~ Company is not required to estimate ESP charges if the expected bill ready data is not received nor is ~~APS~~ Company required to delay ~~APS~~ Company billing. Billing rendered on behalf of the ESP by ~~APS~~ Company shall comply with A.A.C. R14-2-~~1613~~1612.

~~7.2.2.2 If the ESP elects to have APS calculate the ESP charges, APS shall update the customer's records to reflect ESP charges to the customer based upon the pre-defined ESP tariff or charges agreed upon between the ESP and the customer for the ESPs services. APS will calculate both APS and ESP charges, include all charges on the bill, and send the bill either by mail or electronic means to the customer.~~

7.2.2.~~3~~2 ~~APS~~ Company bills shall include in Customer's bill a detailed total of ESP charges and applicable taxes, assessments and billed fees, the ESP's name and telephone number, and other information provided by the ESP.~~the customer's rate schedule number or service offer. Any billing-related details of ESP charges may be provided as specified in the applicable tariff approved by the ACC. These items shall be printed with the APS bill or electronically transmitted to the customer.~~

7.2.2.~~4~~3 ~~APS~~ If Company ~~shall~~ processes ~~C~~customer payments on behalf of the ESP,~~. T~~the ESP shall receive payment for its charges as specified in ~~this Schedule # 10 at~~ Section 7.7~~, Payment and Collection Terms~~.

7.2.3 ESP Obligations

7.2.3.1 Once a billing election is in place as specified in the ESP Service Acquisition Agreement, the ESP may offer ~~APS~~ Company UDC Consolidated Billing services to Direct Access customers pursuant to the terms and conditions of the applicable ACC approved tariff.

7.2.3.2. The ESP shall submit the necessary billing information to facilitate billing services under this billing option by S~~s~~ervice A~~a~~ccount, according to ~~APS'~~ Company's meter reading schedule, and pursuant to the applicable tariff. Timing of billing submittals is provided for in Section 7.2.4 below.

7.2.4 Timing Requirements

7.2.4.1. Bills under this option will be rendered once a month. Nothing contained in this Schedule ~~#10~~ shall limit ~~APS'~~ Company's ability to render bills more frequently consistent with ~~APS'~~ Company's existing practices. However, if ~~APS~~ Company renders bills more frequently than once a month, ESP charges need only to be calculated based on monthly billing periods.

7.2.4.2. Except as provided in Section 7.2.4.1, ~~APS~~ Company shall require that all ESP and ~~APS~~ Company charges be based on the same billing period data.

7.2.4.3. ESP charges for normal monthly customer billing and any adjustments for prior months' metering or billing errors must be received by ~~APS~~ Company in EDI "810" format no later than 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date. If billing charges have not been received from the ESP by this ~~date~~deadline, ~~the last day of the APS bill processing window,~~ APS Company will render ~~the~~ a bill for ~~APS~~ Company charges only~~, without ESP charges~~. The ESP must wait until the next billing cycle, unless there is a mutual agreement for ~~APS~~ Company to send an interim bill. If ~~APS~~ Company renders the bill for ~~APS~~ Company charges only, ~~APS~~ Company will include a note on the bill stating that ESP charges will be forthcoming. An interim bill issued pursuant to this Section may also include a message that ~~APS~~ Company charges were previously billed.

7.2.4.4. ESP charges for a Physical Disconnect Final Bill must be received by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If final billing charges have not been received from the ESP by this date, ~~APS~~ Company will render the customer's final bill for ~~APS~~ Company charges only, without the ESP's final charges. If ~~APS~~ Company renders the bill for ~~APS~~ Company charges only, ~~APS~~ Company will include a note on the bill stating that ESP charges will be forthcoming. The ESP must ~~then produce a separate final bill for their charges, unless otherwise agreed upon by APS and the ESP~~send the final charges to Company. Company will produce and send a separate bill for the final billing charges.

7.2.5. Restrictions

~~7.2.5.1.~~ Company~~APS~~ UDC Consolidated Billing shall be an option for individual customer bills only, not an aggregated group of customers. Nothing in this Section precludes each individual customer in an aggregated group, however, from receiving the customer's individual bills under ~~APS~~ Company UDC Consolidated Billing.

7.3. ESP CONSOLIDATED BILLING

7.3.1 ~~APS~~ Company calculates and sends its bill-ready data to the ESP. The ESP in turn sends a consolidated bill to its customer. The ESP shall be obligated to provide the customer detailed ~~APS~~ Company charges to the extent that the ESP receives such detail from ~~APS~~Company. The ESP is not responsible for the accuracy of ~~APS~~ Company charges.

7.3.2 ~~APS~~ Company Obligations:

7.3.2.1 ~~APS~~ Company shall calculate all ~~APS~~ its charges once per month based on existing Company billing cycles and provide these to the ESP to be included on the ESP consolidated bill or as otherwise specified. ~~APS~~ Company and the ESP may mutually agree to alternative options for the calculation of ~~APS~~ Company charges.

7.3.2.2 ~~APS~~ Company shall provide the ESP with sufficient detail of ~~APS~~ its charges, including any adjustments for prior months' metering and billing error, by EDI "810" format. ~~APS~~ Company charges that are not transmitted to the ESP by 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date need not be included in the ESP's bill. If ~~APS'~~ Company's billing charges have not been received by such date, the ESP may render the bill without ~~APS~~ Company charges unless there is a mutual agreement to have the ESP send an interim bill to the customer including ~~APS~~ Company charges. ~~If the ESP does not include such late-received charges, the ESP shall bill the charges in the next available billing cycle after receipt of the billing data from APS.~~ The ESP will include a message on the bill stating that ~~APS~~ Company charges are forthcoming.

7.3.2.3 For a Physical Disconnect Final Bill, ~~APS~~ Company will provide the ESP with ~~APS'~~ Company's final bill charges by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If ~~APS'~~ Company's billing charges have not been received by such date, the ESP may render the bill without ~~APS~~ Company charges. ~~APS will then render a separate bill for the UDC charges, unless a mutual agreement is made between APS and the ESP to have a final bill produced and sent to the customer for the APS final charges.~~ The ESP shall include a message on the bill stating that ~~APS~~ Company charges are forthcoming. Company will send the final bill charges to the ESP, and the ESP will produce and deliver a separate bill for Company charges.

~~7.3.2.4 APS charges shall be calculated based on existing APS billing cycles regardless of which party provides the meter reading. APS charges shall be conveyed to the ESP electronically or by other means acceptable to both the ESP and APS.~~

7.3.3 ESP Obligations:

7.3.3.1 Once an ESP Service Acquisition Agreement is entered into, including an appropriate billing election, and all other applicable prerequisites are met, the ESP may offer consolidated billing services to Direct Access customers they serve.

7.3.3.2 The ESP bill shall include any billing-related details of ~~APS~~ Company charges. ~~The APS~~ Company charges may be printed with the ESP bill or electronically transmitted. Billing rendered on behalf of ~~APS~~ Company by the ESP shall comply with A.A.C. R14-2-~~1613~~1612.

7.3.3.3 Other than including the billing data provided by ~~APS~~ Company on the customer's bill, the ESP has no obligations regarding the accuracy of ~~APS~~ Company charges ~~calculated by APS~~ or for disputes related to these charges. Disputed charges shall be handled according to ACC procedures.

7.3.3.4 The ESP shall process customer payments and handle collection responsibilities. Under this billing option, the ESP must pay all ~~APS~~ charges due to ~~APS~~ Company and not disputed by the customer as specified in ~~pursuant to~~ Section 7.7.2.1 ~~of this Schedule # 10~~.

7.3.3.5 Subject to the limitations of this Section and with the written consent of the C~~c~~ustomer, the ESP may offer ~~customers~~ Customers customized billing cycles or payment plans which permit the C~~c~~ustomer to pay the ESP for ~~APS~~ Company charges in different amounts than ~~APS~~ Company charges to the ESP for any given billing period. Such plans shall not, however, affect in any manner the obligation of the ESP to pay all Company ~~APS~~ charges ~~as billed by APS~~in full. Should ~~the~~ C~~c~~ustomer select an optional payment plan, all ~~APS~~ Company charges must be billed in accordance with A.A.C. R14-2-210(G).

7.3.4 Timing Requirements

~~7.3.4.1~~ ESPs may render bills more or less frequently than once a month. However, ~~APS~~ Company shall continue to bill the ESP each billing cycle period for the amounts due by the customer for that billing month.

7.4 DUAL COMPANY~~APS~~/ESP BILLING

~~7.4.1~~ ~~APS~~ Company and the ESP each separately bill the customer directly for services provided by them. The billing method is the sole responsibility of Company~~APS~~ and the ESP. ~~APS~~ Company and the ESP shall process only the customer payments relating to their respective charges.

7.5 Billing Information and Inserts

7.5.1 All ~~APS~~ customers, including Direct Access customers, shall receive mandated legal, safety and other notices equally in accordance with A.A.C. R14-2-204 (B). If the ESP is providing consolidated billing, ~~APS~~ Company shall make available one (1) copy of these notices to the ESP for distribution to customers or, at the ESP's request, in electronic format to the ESP for production and communication to electronically billed C~~c~~ustomers. If ~~APS~~ Company is providing ~~consolidated~~ Consolidated billing services, ~~APS~~ Company shall continue to ~~mail~~ provide these notices ~~in the billing envelope and may use the billing envelope as it does in current practices for providing such information~~.

7.5.2 Under ~~APS~~ Company UDC Consolidated Billing, ESP bill inserts may be included pursuant to the applicable ~~APS~~ Company tariff.

7.6 Billing Adjustments for Meter and Billing Error

7.6.1 Meter and Billing Error

7.6.1.1 The MSP (including the ESP or ~~APS~~ Company if providing such services) shall resolve any meter errors and must notify the ESP and ~~APS~~Company, as applicable, so any billing adjustments can be made. ~~Additionally, a~~All other affected parties, including the appropriate Scheduling Coordinator, shall be notified by the ESP.

7.6.1.2 A billing error is the incorrect billing of the C~~c~~ustomer's ~~electrical usage~~energy or demand. If the MSP, MRSP, ESP or ~~APS~~ Company becomes aware of a potential billing error, the party discovering the billing error shall contact the ESP and ~~APS~~Company, as applicable, to investigate the error. If it is determined that there is in fact a billing error, the ESP and ~~APS~~ Company will make any necessary adjustments and notify all other affected parties in a timely manner.

7.6.1.3 ~~APS~~ Company UDC Consolidated Billing

7.6.1.3.1 ~~APS~~ Company shall be responsible for notifying the C~~c~~ustomer and adjusting the bill for ~~APS~~ its charges to the extent those charges were affected by the meter or billing error.

7.6.1.3.2 The ESP shall be responsible for any recalculation of the ESP charges ~~if the ESP is providing bill ready data~~. Following the receipt of the recalculated charges from the ESP, the charges or credits will be applied to the C~~c~~ustomer's next normal monthly bill, unless there is mutual agreement to have ~~APS~~ Company send an interim bill to the customer including the ESP's charges.

~~7.6.1.3.3 APS shall be responsible for any recalculation related to the ESP charges if APS is calculating the ESP charges.~~

7.6.1.4 ESP Consolidated Billing

7.6.1.4.1 The ESP shall be responsible for notifying the C~~c~~ustomer and adjusting the bill for ESP charges to the extent those charges were affected by the meter or billing error. The C~~c~~ustomer shall be solely responsible for obtaining refunds of ESP electric generation overcharges ~~attributable to a fast meter~~ from its current and prior ESPs, as appropriate.

7.6.1.4.2 ~~APS~~ Company shall transmit its adjusted ~~APS~~ charges and any refunds ~~for overcharges~~ to the ESP with the C~~c~~ustomer's next normal monthly bill. The ESP shall apply the charges to the C~~c~~ustomer's next normal monthly bill, unless there is a mutual agreement to have the ESP send an interim bill to the C~~c~~ustomer including ~~the APS~~ Company charges.

7.6.1.5 Dual ~~APS~~Company/ESP Billing

~~7.6.1.5.1~~ ~~APS~~ Company and the ESP shall be separately responsible for notifying the C~~c~~ustomer and adjusting its respective bill for their charges.

7.7 Payment and Collection Terms

7.7.1 ~~APS~~ Company UDC Consolidated Billing

7.7.1.1 ~~APS~~ Company shall remit payments to the ESP for the total ESP charges collected from ~~the~~ C~~c~~ustomer within three (3) working days after ~~the~~ C~~c~~ustomer's payment is received. ~~APS~~ Company is not required to pay amounts owed to the ESP for ESP charges billed but not received by ~~APS~~Company.

7.7.1.2 ~~The~~ C~~c~~ustomer is obligated to pay ~~APS~~ Company for all undisputed ~~APS~~ Company and ESP charges consistent with existing tariffs and other contractual arrangements for service between the ESP and the customer.

7.7.1.3 The ESP is responsible for all collections related to the ESP services on the C~~c~~ustomer's bill, including, but not limited to, security deposits and late charges unless otherwise agreed upon in the customized billing services agreement between ESP and ~~APS~~ Company.

7.7.1.4 Payment for any ~~APS~~ Company charges for ~~APS UDC~~ Consolidated Billing is due in full from the ESP within fifteen (15) calendar days of the date ~~APS'~~ Company charges are rendered to the ESP. ~~All charges received after fifteen (15) calendar days~~Any payment not received within this time frame will be assessed applicable late ~~fees~~ charges pursuant to Schedule # 1. If an ESP fails to pay these charges prior to the next billing cycle, ~~APS~~ Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 ~~of this Schedule # 10~~ may be required.

7.7.2 ESP Consolidated Billing

7.7.2.1 ~~The ESP shall pay amounts owed to APS for undisputed APS charges whether or not the customer has paid the ESP.~~ Payment is due in full from the ESP within fifteen (15) calendar days after the date ~~APS'~~ Company's charges are rendered to the ESP. The ESP shall pay all undisputed ~~APS~~ Company charges ~~due APS~~ regardless of whether ~~the~~ Ccustomer has paid the ESP. All ~~charges~~ payments received after fifteen (15) calendar days will be assessed applicable late ~~fees~~ charges pursuant to Schedule #1. If an ESP fails to pay these charges prior to the next billing cycle, ~~APS~~ Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 ~~of this Schedule # 10~~ may be required.

7.7.2.2 ~~APS~~ Company shall be responsible for any follow-up inquiries with the ESP if there is question concerning the payment amount.

7.7.2.3 ~~APS~~ Company has no payment obligations to the ESP for Ccustomer payments under ESP Consolidated Billing services.

7.7.3 Dual ~~APS~~Company/ESP Billing

~~7.7.3.1~~ ~~APS~~ Company and the ESP are separately responsible for collection of Ccustomer payment for their respective charges.

7.8 Late or Partial Payments and Unpaid Bills

7.8.1 ~~APS~~ Company UDC Consolidated Billing

7.8.1.1 ~~APS~~ Company shall not be responsible for ESP's Ccustomer collections, collecting the unpaid balance of ESP charges from Ccustomers, sending notices informing Ccustomers of unpaid ESP balances, or taking any action to recover the unpaid amounts owed the ESP. The ESP shall assume any collection obligations and/or late charge assessments for late or unpaid balances related to ESP charges under this billing option.

7.8.1.2 All C~~c~~ustomer payments shall be applied first to unpaid balances identified as ~~APS~~ Company charges until such balances are paid in full, then applied to ESP charges. A C~~c~~ustomer may dispute charges as provided by A.A.C. R14-2-212~~and this Schedule # 10~~, but a C~~c~~ustomer will not otherwise have the right to direct partial payments between ~~APS~~ Company and the ESP.

7.8.1.3 ACC rules shall apply to late or non-payment of all ~~APS~~ Company customer charges. Undisputed ~~APS~~ Company delinquent balances owed on a C~~c~~ustomer account shall be considered late and subject to ~~APS~~ Company late payment procedures ~~by APS~~.

7.8.2 ESP Consolidated Billing

~~7.8.2.1~~ The ESP shall be responsible for collecting both unpaid ESP and ~~APS~~ Company charges, sending notices informing C~~c~~ustomers of unpaid ESP and ~~APS~~ Company balances, and taking appropriate actions to recover the amounts owed. ~~APS~~ Company shall not assume any collection obligations under this billing option and ESP is liable to ~~APS~~ Company for all undisputed payments owed ~~APS~~Company.

7.8.3 Dual ~~APS~~Company/ESP Billing

~~7.8.3.1~~ ~~APS~~ Company and the ESP are responsible for collecting their respective unpaid balances, sending notices to C~~c~~ustomers informing them of the unpaid balance, and taking appropriate actions to recover their respective unpaid balances. Customer disputes with ESP charges must be directed to the ESP and C~~c~~ustomer disputes with ~~APS~~ Company charges must be directed to ~~APS~~Company.

7.9 Service Disconnects and Reconnects

~~7.9.1~~ In accordance with ACC rules, ~~APS~~ Company has the right to disconnect electric service to the C~~c~~ustomer for a variety of reasons, including, but not limited to, the non-payment of ~~APS~~ Company's final bills or any past due charges by ~~the~~ C~~c~~ustomer, or evidence of safety violations, energy theft, or fraud, by ~~the~~ C~~c~~ustomer. The following provides for service disconnects and reconnects.

7.9.1~~.1~~ ~~APS~~ Company shall notify ~~the~~ C~~c~~ustomer and ~~the~~ C~~c~~ustomer's ESP of ~~APS'~~ Company's intent to disconnect electric service for the non-payment of ~~APS~~ Company charges prior to disconnecting electric service to the C~~c~~ustomer. ~~APS~~ Company shall further notify the ESP at the time ~~the~~ C~~c~~ustomer has been disconnected. To the extent authorized by the ACC, a service charge shall be imposed on ~~the~~ C~~c~~ustomer if a field call is performed to disconnect electric service.

7.9.~~1.~~2 ~~APS~~ Company shall reconnect electric service for ~~an ACC-authorized service~~a fee when the criteria for reconnection have been met to ~~APS'~~ Company's satisfaction. ~~APS~~ Company shall notify the ESP of a C~~c~~ustomer's reconnection.

7.9.~~1.~~3 ~~APS~~ Company shall not disconnect electric service to ~~the~~ Ccustomer for the non-payment of ESP charges by ~~the~~ Ccustomer. In the event of non-payment of ESP charges by ~~the~~ Ccustomer, the ESP may submit a DASR requesting termination of the service agreement and request return to ~~APS~~ Company Standard Offer Service. ~~APS~~ Company will then advise the Ccustomer that they will be placed on ~~APS~~ Company Standard Offer Service unless a DASR is received from another ESP on their behalf.

7.10. Involuntary Service Changes

7.10.1. ~~Service Changes~~A Customer may have its service of electricity, billing, or metering from an ESP changed to another provider, including Company, involuntarily in the following circumstances:

~~7.10.1.1. A customer may have its service of electricity, billing, or metering from an ESP changed to another provider, including APS, involuntarily in the following circumstances:~~

7.10.1.1.~~1.~~ The ACC has decertified the ESP or the ESP otherwise receives an ACC order that prohibits the ESP from serving the customer.

7.10.1.~~1.2.~~2 The ESP, including its agents, has materially failed to meet its obligations under the terms of its ESP Service Acquisition Agreement with ~~APS~~ Company (including applicable tariffs and schedules) so as to constitute an Event of Default under the terms of the ESP Service Acquisition Agreement, and ~~APS~~ Company exercises its contractual right to terminate the ESP Service Acquisition Agreement.

7.10.1.~~1.3.~~3 The ESP has materially failed to meet its obligations under the terms of the ESP Service Acquisition Agreement (including applicable tariffs and schedules) so as to constitute an Event of Default and ~~APS~~ Company exercises a contractual right to change billing options.

7.10.1.~~1.4.~~4 The ESP ceases to perform by failing to provide schedules through a Scheduling Coordinator ~~wherever~~ whenever such schedules are required, or the ESP fails to have a Service Acquisition Agreement in place with a Scheduling Coordinator.

7.10.1.~~1.5~~5. The Ccustomer fails to meet its Direct Access requirements and obligations under the ACC rules and ~~APS'~~ Company tariffs and schedules.

7.10.2. Change of Service Election in Exigent Circumstances

~~7.10.2.1.~~In the event ~~APS~~ Company finds that an ESP or the ~~c~~Customer has materially failed to meet its obligations under this Schedule ~~# 10~~ or the ESP Service Acquisition Agreement such that ~~APS~~ Company elects to invoke its remedies under ~~this~~ Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.~~1.~~3) and the failure constitutes an emergency (defined as posing a substantial threat to the reliability of the electric system or to public health and safety), or the failure relates to ESP's sale of unscheduled energy, ~~APS~~ Company may initiate a change in the ~~c~~Customer's service election, or terminate an ESP's ability to offer certain services under Direct Access. In such case, ~~APS~~ Company shall initiate the change or termination by preparing a DASR, but the change or termination may be made immediately notwithstanding the applicable DASR processing times set forth in this Schedule ~~# 10~~. ~~APS~~ Company shall provide such notice and opportunity to ~~cure~~ remedy the problem if there are reasonable circumstances prevailing~~as is reasonable under the circumstances, if any is reasonable~~. Additionally, ~~APS~~ Company shall notify the ACC of the circumstances that required the change or the termination and the resulting action taken by ~~APS~~Company. The ESP and/or ~~c~~Customer shall have the right to seek an order from the ACC restoring the customer's service election and/or the ESP's ability to offer services. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to ~~the~~ ~~c~~Customer other than as provided in Section 4.4.2 ~~of this Schedule # 10~~.

7.10.3. Change in Service Election Absent Exigent Circumstances

7.10.3.1. In the event ~~APS~~ Company finds that an ESP has materially failed to meet its obligations under this Schedule ~~# 10~~ or the ESP Service Acquisition Agreement such that ~~APS~~ Company seeks to invoke its remedies under ~~this~~ Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.~~1.~~3), and the failure does not constitute an emergency (as defined in Section 7.10.2~~.1~~) or involve an ESP's unauthorized energy use, ~~APS~~ Company shall notify the ESP and the ACC of such finding in writing stating the following:

7.10.3.1.1. The nature of the alleged failure;

7.10.3.1.2. The actions necessary to ~~cure~~ remedy the failure;

7.10.3.1.3. The name, address and telephone number of a contact person at ~~APS~~ the Company authorized to discuss resolution of the failure.

7.10.3.2. The ESP shall have thirty (30) calendar days from receipt of such notice to ~~cure~~ remedy the alleged failure or reach an agreement with ~~APS~~ Company regarding the alleged failure. If the failure is not ~~cured~~ remedied and no agreement is reached between ~~APS~~ Company and the ESP following this thirty (30) day period, ~~APS~~ Company may initiate the DASR process set forth in this Schedule ~~# 10~~ to accomplish its remedy and shall notify the customers of such remedy. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to the customer other than as provided in Section 4.4.2 ~~of this Schedule # 10~~.

7.10.4. Termination of ESP Consolidated Billing

~~7.10.4.1. ESP Consolidated Billing may be terminated under the circumstances set forth in this Section 7.10.4. This Section 7.10.4 sets forth the notice and opportunity to cure provisions applicable to defaults that permit a remedy of terminating ESP Consolidated Billing under this Schedule # 10 (which is incorporated by reference in the ESP Service Acquisition Agreement)~~

7.10.4.~~2~~1. ~~APS~~ Company may terminate ESP Consolidated Billing under the following circumstances:

7.10.4.~~2.~~1.1. ~~If APS finds that the information provided by the ESP in the ESP Service Acquisition Agreement is materially false, incomplete or inaccurate; the ESP attempts to avoid payment of ACC-authorized APS charges; or the ESP files for bankruptcy, fails to have an involuntary bankruptcy proceeding filed against the ESP dismissed within sixty (60) calendar days, admits insolvency, makes a general assignment for the benefit of creditors, is unable to pay its debts as they mature, or has a trustee or receiver appointed over all or a substantial portion of its assets, APS shall notify affected customers that ESP Consolidated Billing services will be terminated, and APS may switch affected customers to Dual Billing as promptly as possible~~The Company shall notify affected Customers that ESP Consolidated Billing services will be terminated, and the Company may switch affected Customers to Dual Company/ESP billing as promptly as possible if any of the following occur:~~.~~

7.10.4.1.1.1 Company finds that the information provided by the ESP in the ESP Service Acquisition Agreement is materially false, incomplete, or inaccurate.

7.10.4.1.1.2 The ESP attempts to avoid payment of Company charges.

7.10.4.1.1.3 The ESP files for bankruptcy.

7.10.4.1.1.4 The ESP fails to have an involuntary bankruptcy proceeding filed against the ESP dismissed within sixty (60) calendar days.

7.10.4.1.1.5 The ESP admits insolvency.

7.10.4.1.1.6 The ESP makes a general assignment for the benefit of creditors.

7.10.4.1.1.7 The ESP is unable to pay its debts as they mature.

7.10.4.1.1.8 The ESP has a trustee or receiver appointed over all, or a substantial portion, of its assets.

7.10.4.1.2.2. If the ESP fails to pay ~~APS~~ Company (or dispute payment pursuant to the procedures set forth in this Schedule ~~# 10~~) the full amount of all ~~APS~~ Company charges and fees by the applicable due date, ~~APS~~ Company shall notify the ESP of the past due amount within two (2) working days of the applicable past due date. If the ESP incurs late charges on more than ~~three (3)~~ two (2) occasions or fails to pay overdue amounts including late charges within five (5) working days of the receipt of notice by ~~APS~~ Company, ~~APS~~ Company may notify the ESP's customers and the ESP that ESP Consolidated Billing services will be terminated, and that C~~c~~ustomers shall be switched to Dual Billing.

7.10.4.1.2.3. If the ESP fails to comply within thirty (30) calendar days of the receipt of notice from ~~APS~~ Company of any additional credit, security or deposit requirements set forth in Sections 5.1.4 and 7.11 ~~of this Schedule # 10~~, ~~APS~~ Company may notify the ESP that ESP Consolidated Billing services will be terminated, and that C~~c~~ustomers shall be switched to Dual Billing.

7.10.4.32. Upon termination of ESP Consolidated Billing pursuant to ~~this~~ Section 7.10.4, ~~APS~~ Company may deliver a separate bill for all ~~APS~~ Company charges which were not previously billed by the ESP.

7.10.4.43 ~~APS~~ Company may reinstate the ESP's eligibility to engage in ESP Consolidated Billing upon a reasonable showing by the ESP that the problems causing the revocation of ESP Consolidated Billing have been cured, including payment of any late charges, reestablishing credit requirements in compliance with Sections 5.1.34 and 7.11, and payment to ~~APS~~ Company of all costs associated with changing ESP customers' billing elections to and from dual billing.

7.10.4.54 In the event ~~APS~~ Company terminates ESP Consolidated Billing, ~~APS~~ Company will return any security posted by the ESP pursuant to the ESP Service Acquisition Agreement.

7.10.5. Termination of ~~APS~~ Company UDC Consolidated Billing

7.10.5.1. ~~APS~~ Company may terminate ~~APS~~ Company UDC Consolidated Billing and revert to Dual Billing upon providing thirty (30) calendar days notice to an ESP if ESP fails to ~~timely~~ pay ~~APS~~ Company charges in connection with ~~APS~~ Company UDC Consolidated Billing or otherwise fails to comply with its obligations under Section 7.2 ~~of this Schedule # 10~~.

7.10.5.2 ~~APS~~ Company may terminate ~~APS UDC~~ Consolidated Billing upon providing thirty (30) days notice to an ESP if ~~APS~~ Company cancels or changes the tariff governing ~~APS~~ Company UDC Consolidated Billing.

7.10.6. Upon termination of ESP Direct Access services pursuant to ~~this~~ Section 7.10, the provision of the affected service(s) shall be assumed by another eligible ESP from which the C~~c~~ustomer elects to obtain the affected service(s). Absent an election by ~~the~~ C~~c~~ustomer, ~~APS~~ Company shall provide such services, until such time that ~~the~~ C~~c~~ustomer makes an election.

7.10.7. ~~APS~~ Company shall not use involuntary service changes in an anticompetitive or discriminatory manner.

7.11. ESP Security Deposits

7.11.1. ~~APS~~ Company may, ~~in~~ at its discretion, require cash security deposits from any ESP that has on more than one occasion failed to ~~timely~~ pay ~~APS~~ Company charges or ACC-approved Direct Access charges within the established time frame, such as DASR fees, meter or billing error or service fees, and other fees applicable to an ESP through ~~this~~ Schedule ~~#~~ 10 and ~~APS'~~ Company's other tariffs and schedules.

7.11.2. The amount of the security deposit required shall not exceed two and one-half times the estimated maximum monthly bill to the ESP for such charges, and a separate security deposit may be required for separate categories of ESP or Direct Access charges.

7.11.3. Security deposits required pursuant to ~~this~~ Section 7.11 shall be in the form of a cash deposit accruing interest as specified in Section 2.~~6~~7.~~3~~4 of ~~APS'~~ Company Schedule ~~#~~ 1. ~~APS~~ Company shall issue the ESP a nonnegotiable receipt for the amount of the deposit.

7.11.4. ~~APS~~ Company may refuse to accept DASRs from, or provide other ~~APS~~ Company services to, an ESP that fails to comply within thirty (30) calendar days to a demand that the ESP establish a security deposit pursuant to ~~this~~ Section 7.11.

8. Meter Services

8.1 Under Direct Access, ESPs may offer certain metering services for Direct Access implementation, including meter ownership, ~~Meter Service Provider (~~MSP~~)~~ and ~~Meter Reading Service Provider (~~MSRP~~)~~ services.

8.2 ~~APS~~ Company has the right to offer the following meter services:

8.2.1 Metering and Meter Reading for Residential Load-Profiled Customers

~~8.2.2 All competitive Metering or Meter Reading services whenever there are no authorized providers available to supply services to a particular class of customers or location.~~

~~8.2.3~~ 8.2.2 Services as authorized by the ACC.

~~8.2.4~~ 8.2.3 ~~APS~~ Company reserves the right to perform meter disconnects, regardless of meter ownership, in cases of potential safety hazards or non-payment for ~~APS~~ Company charges.

8.3 A~~n~~ Load Serving ESP may sub-contract Metering or Meter Reading Services to a ~~qualified~~ certificated third party. If the ESP sub-contracts any of the components of these services to a third party, the ESP shall, for the ~~proposes~~ purposes of this Schedule ~~# 10~~, remain responsible for the services.

8.4 Load Serving ESPs providing Metering or Meter Reading Services to Direct Access customers either on their own or through a third party assume full responsibility for meeting the applicable meter and communication standards, as well as assuming responsibility for the safe installation and operation of the meter and any personal injuries and damage caused to customer or ~~APS~~ Company property by the meter or its installation. This liability will lie with the ESP regardless of whether the ESP or its subcontractors perform the work.

8.5 Meter Specifications

8.5.1 The Director of Utilities Division of the ACC has determined the following specifications and standards shall apply to competitive metering where applicable (see Performance Metering Specifications and Standards document):

8.5.2 Metering standards (American National Standards Institute):

ANSI C12.1	Code for Electricity Metering
ANSI C12.6	Marketing & Arrangement of Terminals for Phase Shifting Devices used in Metering
ANSI C12.7	Watt-hour Meter Socket
ANSI C12.10	Electromechanical Watt-hour Meters
ANSI C12.13	Electronic TOU Registers for Electricity Meters
ANSI C12.18	Type 2 Optical Port
ANSI C12.20	0.2% & 0.5% Accuracy Class Meters
ANSI C37.90	Surge Withstand Test
ANSI 57.13	Instrument Transformers (All CTs & PTs)
ANSI Z1.4	Sampling Procedures and Tables for Inspection
ANSI Z1.9	Sampling Procedures and Tables for Inspection

8.5.3 EEI Electricity Metering Handbook

8.5.4 Electric Utilities Service Equipment Requirements Committee (EUSERC)

8.5.5 ~~National Electric Code (~~NEC~~)~~ & Local Requirements by jurisdictions

8.5.6 ~~APS~~ Company's Electric Service Requirements ~~Handbook~~Manual (ESRM)

8.5.7 National Electrical Safety Code (NESC)

8.5.8 ESPs or their contractors providing competitive metering services shall also comply with such other specifications or standards determined to be applicable or appropriate by the ACC's Director of Utilities Division.

8.6 Meter Conformity

8.6.1 All Direct Access meters shall have a visual kWh display and must have a physical interface to enable on-site interrogation of all stored meter data. All meters installed must support the ~~customer's APS~~Company's rate ~~tariff~~schedules.

8.6.2 If ~~APS~~ Company is providing MRSP functions for the ESP, pursuant to the Rules, meters must be compatible with ~~APS'~~ Company's meter reading system.

8.6.3 No meter or associated metering equipment shall be set or allowed to remain in service if it is determined that the meter or its associated equipment did not meet ~~APS' existing~~ approved specifications, as set forth in ~~APS'~~ Company's ~~Electric Service Requirements Manual~~ ESRM, or is in violation of any code listed in Section 8.5 ~~in place at the time of installation~~.

8.7 Meter Testing

8.7.1 If a manufacturer's sealed meter has not previously been set and the meter was tested within the last twelve (12) months, the meter shall be deemed in compliance with ACC standards without additional testing.

8.7.2 Any meter removed from service shall be processed according to the following table prior to its re-installation:

METER TYPE	REMOVAL REASON	ACTION REQUIRED
1 Ph ~~KWH only~~kWh Electro-Mechanical	Routine	Meter Inspection
1 Ph ~~KWH only~~kWh Electro-Mechanical	Trouble	Meter ~~Calibration~~ Test
1 Ph ~~TOU or Solid State~~kWh Hybrid or Solid State	Routine	~~Reprogram and Meter Inspection~~Meter Test
1 Ph TOU ~~or Solid State~~(all)	Trouble	Meter ~~Calibration~~ Test
3 Ph Meters (all)	All	Meter ~~Calibration~~ Test
1 Ph or 3 Ph IDR Meters	All	Meter ~~Calibration~~ Test

8.7.3 Meter tests are to be conducted in accordance with ANSI C12.1 recommended testing standards.

8.7.~~3~~4 Records on ~~calibration~~ meter testing shall be maintained by the MSP and provided to the requesting parties within three (3) working days of such a request for such records. The latest ~~calibration~~ meter test record shall be kept as long as the meter is in service.

8.8 Meter Test Requests

~~8.8.1~~ Pursuant to A.A.C. R14-209(F), either party may request that the other party perform a meter test, in which instance the requesting party is entitled to witness the test if it so chooses. The requesting party shall be notified of the test date and written test results from the testing party. If the meter is found to be within ACC-approved standards, the requesting party shall reimburse the other party for all costs incurred in the process of testing the meter (per ACC approved tariffs). The MSP shall take reasonable measures to detect meter error. The MSP shall notify ~~APS~~ Company as soon as it becomes aware of any meter that is not operating in compliance with ACC performance specifications. The MSP shall make any repairs or changes required to correct the error. ESPs and ~~APS~~ Company shall use a ~~Direct Access Meter Notification~~ form approved by the ACC Process Standardization Working Group (PSWG) to initiate and respond to such action.

8.9 Meter Identification

8.9.1 The ESP or its agent shall install a~~n APS~~ Company provided unique ~~meter~~ number on each meter. ~~APS~~ Company will provide the unique ~~meter~~ numbers printed on stickers in blocks of up to 1,000 numbers. These stickers must be readily visible from the front of the meter. The number assigned to that meter shall remain solely with that meter while in use in Company's service territory.

8.9.2 When an ESP installs either its own meter or a customer owned meter, the ring or lock ring must be secured with a blue seal that is imprinted with the name ~~of the load serving ESP's name~~ ~~or~~and/or logo of the ESP or their agent.

8.10 Installation of metering equipment

8.10.1 All metering equipment shall be installed according to all applicable ACC requirements and ~~APS~~ Company's Electric Service Requirements Manual.

8.10.2 An ESP or its agent must be authorized by ~~APS~~ Company to remove ~~an APS~~a Company owned meter ~~or PTs and CTs. Once authorized, when the ESP or its agent intends to remove an APS meter with or without CTs and PTs and install a new meter with or without CTs and PTs in its place, APS must first receive a completed Direct Access Meter Notification Form. This must be submitted to APS at least five (5) working days prior to the meter set. Under no circumstances shall an ESP or its agent remove APS metering or metering equipment without prior notification to APS. Notwithstanding the foregoing, ESP or its agent shall schedule a meter exchange so that the Direct Access Meter Notification Form is received by APS by the end of business six (6) working days before the scheduled read date. During the phase-in period (January 1, 1999 through December 31, 2000) the meter exchange must be completed within 60 days of the date that the RQ DSAR is submitted.~~ The Existing Meter Information (EMI) form will be sent to the ESP and MSP within five (5) working days within receiving the DASR acceptance notification indicating a pending meter exchange. When the MSP intends to remove a Company meter, Company must receive a Meter Data Communication Request (MDCR) format at least five (5) working days prior to the exchange. Upon completion of the meter exchange, the MSP will return the Meter Installation/Removal Notification (MIRN) form to Company by the end of business, three (3) working days from the day of the exchange.

8.10.3 The ESP or its agent shall inform ~~APS~~ Company of all meter activity, such as meter installations or exchanges, ~~CT and PT exchanges~~ via the ~~Direct Access Meter Notification Form~~Meter Activity Coordination (MAC) Form within the time frames specified above. ~~Additionally, ESP must provide APS with the most recent meter calibration test data.~~ If final meter reads are not provided to ~~APS~~Company, are inaccurate, or otherwise result in ~~APS~~ Company not being able to render accurate final bills to customers pursuant to ACC ~~R~~rules and ~~R~~regulations, the ESP shall be responsible for any unbilled, disputed, or unrecoverable amounts and applicable late charges.

8.10.4 The ESP or its agent shall return the existing meter ~~with any removed PTs and CTs~~ to ~~APS~~ Company at one of ~~APS'~~ Company's designated locations ~~throughout APS' service territory~~identified in the meter drop off list within fifteen (15) working days after its removal, or be charged the cost of the meter and metering equipment and /or any other charges per the applicable ACC-approved tariff. The ESP or its agent shall be responsible for damage to the meter occurring during shipment.

8.11 On-Site Inspections/Site Meets

8.11.1 ~~APS~~ Company may perform on-site inspections of meter installations. The ESP shall be notified if the inspections uncover any material non-compliance by the MSP with the approved specifications and standards.

8.11.2 For new construction, the party installing the meter shall ensure that the owner/builder has met the construction standards outlined in ~~the APS~~ Company's ~~Electric Service Requirements Manual~~ESRM, and ~~the APS~~ Company's Transmission and Distribution construction manual, as well as local municipal agency requirements, and any updates, supplements, amendments and other changes that may be made to these manuals and requirements. ~~APS~~ Company shall perform a pre-installation inspection on all new construction. Local city/county clearances may also be required prior to energizing any new construction.

8.11.3 ~~APS~~ Company may require a site meet for: ~~to exchange or remove~~ the exchange or removal of an IDR meter which requires an optical device to retrieve interval data; the exchange or removal of equipment at an existing totalized metering installation; a restricted access location for which ~~APS~~ Company forbids key access; co-generation sites, bi-directional or detented metering sites; or ~~on~~ upon request of an ESP or MSP. The ESP and ~~APS'~~ Company's MAC shall coordinate the time of the site meet. If the ESP or MSP misses~~es~~ two (2) site meets, ~~APS~~ Company may cancel the applicable DASR. ~~APS~~ Company may charge for a site meet requested by the ESP or MSP, or if the ESP or MSP fails to arrive within thirty (30) minutes of the appointment time, or if the ESP fails to cancel a site meet at least one (1) working day in advance of the appointment time.

8.12 Meter Service Options and Obligations

8.12.1 Meter Ownership shall be limited to ~~APS~~Company, an ESP, or the customer. The customer must obtain the meter through ~~APS~~ Company or an ESP. Although a customer may own the electric meter, maintenance and servicing of the metering equipment shall be limited to ~~APS~~Company, the ESP, or the ESP's qualified representative (MSP).

8.12.2 ~~If the ESP or customer owns the meter, the ESP must~~Company shall own the CTs, PTs and associated equipment~~, except as provided in section 8.12.3. The ESP may purchase existing CTs and PTs and associated metering equipment from APS~~.

~~8.12.3 The following provisions apply to the ownership of CTs and PTs:~~

~~8.12.3.1 For distribution voltages up to 25kv, the ESP or APS shall own the CTs and PTs. For transmission primary voltages (over 25kv), the CTs and PTs shall be owned by APS. ESP owned CTs & PTs must meet APS specifications. No CTs and PTs or associated metering equipment shall be set or allowed to remain in service if it is determined that the CTs and PTs or its associated equipment did not meet APS' approved specifications, as set forth in APS' Electric Service Requirements Manual, in place at the time of installation.~~

8.12.43 All CT-rated meter installations shall utilize safety test switches, and all self-contained commercial metering shall utilize safety-test blocks as provided in ~~the APS~~ Company's ~~Electric Service Requirements Manual~~ESRM. During meter exchanges, the ESP or its agent's employees who are ~~certified~~ certificated to perform the related MSP activities may install, replace or operate ~~APS~~ Company test switches and operate ~~APS~~Company-sealed customer-owned test blocks.

~~8.12.5 Direct Access premises with multiple service entrance sections will be considered separately for metering purposes. Existing totalizing installations will be discontinued upon a customer's entrance into Direct Access.~~

8.13 Installation Options

8.13.1 ~~The ESP may choose from the following list of options for meter installation:~~The ESP is responsible for Direct Access customer meter installation. Company may optionally provide meter installation pursuant to the Rules.

~~8.13.1.1 ESP owned/ESP installed metering~~

~~8.13.1.2 ESP owned/APS installed metering~~

~~8.13.1.3 Customer owned/ESP installed metering~~

~~8.13.1.4 Customer owned/APS installed metering~~

~~8.13.1.5 APS owned/APS installed metering.~~

8.13.2 ESPs or their agents must be ~~certified~~ certificated by the ACC in order to offer MSP services. The policies and procedures described in this Section 8.13 assume that the MSP ~~service provider~~ and ~~his~~ their meter installers have ACC certification. ESPs may elect to offer metering services by:

8.13.2.1 Becoming a ~~certified~~ certificated ~~Metering Service Provider~~MSP.

8.13.2.2 Subcontracting with a third party that is a ~~certified~~ certificated MSP.

8.13.2.3 Subcontracting with ~~APS~~ Company under the circumstances described in Section 8.2 ~~of this Schedule # 10~~.

8.14 As part of providing metering services, ESPs or their agents shall:

8.14.1 Obtain lock ring keys for meters originally installed by ~~APS~~ Company or request site meets with ~~APS~~Company. ~~APS~~ Company will issue lock ring keys to certified MSPs upon receipt of a refundable deposit. The deposit will not be refunded if a key is either lost or stolen, and a fee will be applied to replace lost or damaged keys. For more information about the cost of lock rings, standard rings, or lock ring keys, please consult the ~~APS~~ Company MAC.

8.14.2 If lock rings are used they shall meet ~~APS~~ Company requirements. If a meter is installed and the readings are obtained from a source other than a physical inspection, a lock ring must be utilized. Lock rings may be purchased from ~~APS~~Company.

8.14.3 Provide information to ~~APS~~ Company on the specifications and other specifics on meters not purchased from or installed by ~~APS~~Company.

8.14.4 ~~For customers transferring from Direct Access to Standard Offer service, the ESP shall either allow APS to remove the customer's meter , or schedule a joint meet to remove the meter.~~Allow Company to remove the customer's meter, or schedule a site meet to remove the meter transferring from Direct Access to Standard Offer service. If the ESP allows ~~APS~~ Company to remove meters, ESP shall coordinate with the ~~APS~~ Company ~~MAC~~ regarding the return of ~~ESP's~~ the meters.

8.14.5 Be responsible for obtaining and providing reads from any meter that it installs from the time it is installed to the time it is removed or until meter reading responsibilities are assumed by another ESP or the customer returns to Standard Offer service.

8.14.6 Ensure that ESP and MSP employees working in ~~APS~~ Company's territory follow ACC, and other applicable safety standards.

8.14.7 ~~In the event that unauthorized energy use is suspected and a safety hazard exists, notify APS immediately, or within twenty-four (24) hours for non-safety issues, and cooperate with APS in response thereto.~~Company shall notify the ESP immediately and the ESP shall notify Company immediately of any suspected unauthorized energy use when a safety hazard exists. In instances where there is not a safety hazard, each party will notify each other within twenty-four (24) hours. The ESP shall ensure that a lock ring is installed to secure any meter that does not require a monthly local (i.e., manual) meter read. The Parties agree to preserve any evidence of unauthorized energy use. Once unauthorized energy use is suspected, Company, in its sole discretion, may take any or all of the actions permitted under Company's tariffs and schedules and shall notify the ACC of any such action taken.

8.14.8 ~~ESPs and their agents shall take~~ Take no action to impede ~~APS'~~ Company's safe and unrestricted access to a customer's service entrance.

8.14.9 Glass over any socket when a meter is removed and a new meter is not installed.

8.15 ~~MRSP~~ MSRP Services provided as a responsibility of an ESP

~~8.15.1 MRSP functions shall be performed by certified MRSPs on the ESP's behalf in accordance with ACC regulations, and shall be the responsibility of the party specified in the DASR. MRSP obligations and responsibilities are as stated in the ACC's Rules and requirements and include:~~Only certificated MRSP's acting on the ESP's behalf in accordance with ACC regulations shall perform MRSP functions. The MRSP for each Direct Access customer will be specified on the DASR received from the ESP. Any changes to Customers MRSP will be updated by the ESP with a "UC" DASR at least ten (10) days prior to the next schedules read date. MSRP obligations and responsibilities are stated in the ACC's Rules and Regulations and include:

8.15.1~~.1~~ Meter data for Direct Access Customers shall be read, validated, edited, and transferred pursuant to ~~ACC approved standards~~Arizona's Validation, Editing, and Estimation Process (VEE). It is the responsibility of the MRSP to comply with this process. In cases where validated data is unavailable for transfer by the posting deadline, it is the responsibility of the MRSP to provide an estimated data file for the entire read cycle until actual meter data is available. At such time as actual data becomes available, a corrected data file shall be posted immediately.

8.15.~~1.~~2 Both ~~APS~~ Company and the ESP shall have 24-hour/7 days per week access to the MRSP server.

8.15.~~1.~~3 Meter read data shall include~~ing~~ beginning and ending reads as well as the validated usage for load-profiled customers. Validated interval data shall be provided for all interval metering customers. Data must ~~shall~~ be posted to the MRSP server using the Arizona Standard EDI "867" format. Estimated ~~reads, along with reasons for the estimate, shall be included with the reads on the MRSP server. The EDI format specification includes the estimated read reason codes to be used~~data shall contain applicable reason codes pursuant to the 867 guidelines.

8.15.~~1.~~4 The MRSP shall provide ~~APS~~ Company with access to meter data at the MRSP server as required to allow the proper performance of billing and settlement.

8.15.~~1.~~5 MRSPs must have a CC&N from the ACC authorizing it to offer MSRP services, and must be certified in Company territory.

8.15.~~1.~~6 MRSPs shall read ~~the~~ Customer's meter ~~on the APS read cycle. MRSP shall provide APS with meter reading data in a manner that conforms to APS' billing cycles in accordance with A.A.C. R14-2-209~~based on the scheduled read date per Company's Yearly Meter Read Schedule. The billing cycle for each meter shall contain the full period from read date to the following read date. Interval data cycles shall be considered from 00:15 on the read date to 00:00 on the following read date (i.e. 9/1/00 00:15 through 10/1/00 00:00). The first complete interval timestamp shall begin at 00:15 in each cycle. For meter exchanges to Direct Access, the first complete interval through the first read date at 00:00 shall constitute the billing cycle. For meter exchanges back to Standard Offer, every interval shall be included up to the last full interval prior to the exchange. It is the responsibility of the MRSP to provide estimation of any intervals that are necessary to constitute the full billing cycle.

8.15.~~1~~.7 The MRSP shall provide re-reads or read verifies within ten (10) working days of a request by ~~APS~~ Company or ~~the~~ ~~C~~customer. The requesting party may be charged per the applicable ACC tariff if the original read was not in error.

8.16 Meter Reading Data Obligations

8.16.1 Accuracy for all meters.

8.16.1.1 Meter clocks shall be maintained according to Arizona time within +/- three (3) minutes of the National Time Standard.

8.16.1.2 Meter read date and time shall be accurate.

8.16.1.3 All meter reading data shall be validated with the ~~applicable ACC approved requirements~~pursuant to the approved Arizona VEE guidelines.

8.16.2 Timeliness for Validated Meter Reading Data

~~8.16.2.1~~ Pursuant to guidelines established by the Utilities Division Director, ~~timeliness requirements for the delivery of data. O~~one hundred percent (100%) of the validated meter ~~reads~~ data shall be available by 3:00 p.m. local Arizona time (MST) on the third working day after the scheduled read date. If the meter ~~reads are~~data is not posted, ~~or available~~is unavailable, or ~~are posted~~ clearly ~~in error by 3:00 p.m. on the third working day after the scheduled read date~~contains errors by this deadline, the ~~read~~ billing determinants including usage (kWh) and demand (kW) may be estimated ~~or read by APS~~by Company and the ESP shall be charged an approved charge for this service. ~~For newly installed IDR meters, IDR reads shall include the meter read, the interval data and enough information to calculate the read and total consumption to the exact cut-over date and time.~~

8.16.3 Proof of Operational Ability

~~8.16.3.1~~ Prior to performing ~~MSRP~~ MRSP services in ~~APS'~~ Company's distribution service territory, or prior to making any significant change in MRSP service methodology, each ~~MSRP~~ MRSP will perform compliance testing to demonstrate its ability to read meters, validate data, edit data, estimate missing data and post validated data in ~~APS~~Company-compatible EDI format to the MRSP server. In addition, upon installation of the initial meter on Direct Access accounts in ~~APS'~~ Company's distribution service territory, each MRSP shall prove its ability to read its meters and post validated data in ~~APS~~Company-compatible EDI format to the MRSP server. If the MRSP is unsuccessful in its attempts to meet these requirements, all subsequent requests for meter exchanges will be postponed until the ~~MSRP~~ MRSP successfully demonstrates its operational ability.

8.16.4 Retention and Format for Meter Reading Data

8.16.4.1 All meter reading data for a ~~C~~customer shall remain posted on the MRSP server for five (5) working days and will be recoverable for at least three (3) years.

8.16.4.2 Meter reading data posted to the MRSP server shall be stored in ~~APS~~Company-compatible EDI format.

8.17 ~~APS~~ Company performing MSP and MRSP functions:

~~8.17.1~~ If ~~APS~~ Company is eligible to perform Direct Access related MSP and MRSP functions as defined in section 8.2, the following restriction applies:

~~8.17.1.1 For the period January 1, 1999 to December 31, 2000 for load profiled customers in which APS is reading the meter, t~~The validated meter read will be posted in EDI format no later than six (6) working days following the scheduled read date.

8.18 Non-Conforming Meters, Meter Errors and Meter Reading Errors

8.18.1 Whenever ~~APS~~Company, the ESP or its agents becomes aware of any non-conforming meters, erroneous meter services and/or meter reading services that impact billing, it shall promptly notify the other parties and the affected ~~C~~customer ~~in question~~. Bills found to be in error due to non-conforming meters or errors in meter services or meter reading services will be corrected by the appropriate parties.

8.18.2 In cases of meter failure or non-compliance, the ESP or its agents shall have five (5) working days to correct the non-compliance. If the non-compliance is not remedied within five (5) working days, the following actions may apply:

8.18.2.1 A site meeting may be required when services are being performed. The non-compliant party ~~will~~ may be charged an ACC-approved tariff for the meeting.

8.18.2.2 ~~APS~~ Company may repair the defect, and the other party shall be responsible for all related expenses.

8.18.2.3 ~~Upon a demonstrated pattern of non-compliance (with ACC requirements and this Schedule #10) and failure to correct the problem in a timely manner, APS may give written notice to the non-compliant party and to the ACC. After five (5) working days, APS may suspend processing DASRs from an ESP that uses an MSP or MRSP that is non-compliant until such non-compliance is corrected to APS' satisfaction.~~Company shall adhere to the approved Performance Monitoring Standards and follow the steps outlined to address non-compliance by an MRSP.

~~8.18.2.4 A pattern of non-compliance by an ESP is defined by the following conditions:~~

~~8.18.2.4.1 If more than one percent (1%) of the service accounts served by an ESP, or five (5) accounts, whichever is greater, are found to be non-conforming and are not corrected during the first six months of Direct Access participation by that ESP.~~

~~8.18.2.4.2 More than one-half of one percent (0.5%), or three (3) accounts, whichever is greater, are found to be non conforming and are not corrected during any six consecutive months thereafter.~~

8.18.3 ~~APS~~ Company may refuse to enter into a new ESP Service Acquisition Agreement, or cancel an existing ESP Service Acquisition Agreement pursuant to S~~s~~ection 7.10~~.1.1.2~~, with any ESP or its agents that has a demonstrated pattern of uncorrected non-compliance as established above. This provision shall not apply if the alleged demonstrated pattern of non-compliance or correction thereof is disputed and is pending before any agency or entity with jurisdiction to resolve the dispute.

SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION OF SPECIALIZED METERING

Arizona Public Service Company (Company) will provide specialized metering upon customer request, provided the customer agrees to the following conditions:

1. The customer must contact their Company Account Representative to request and coordinate the purchase and installation of specialized metering such as KYZ pulse meters, IDR meters, or IDR and KYZ pulse meters. The customer must specify whether a modem will be required.

2. If the customer requests a meter with a modem option, the customer will be required to install communication equipment and connections which shall include a RJ11 or RJ12 jack. A coil of communication cable with either an RJ11 or RJ12 jack is to be provided within five to ten feet of the meter panel location and in such a manner that will provide for ease of attachment of the jack to the meter panel by Company. The phone line must be installed prior to the installation of the meter. The customer must provide Company with a phone number and any other communication access information to the meter(s) prior to Company installation of the meter(s).

3. If a customer requests kWh pulses, Company shall furnish an isolation relay and maintain the output wire and connections from this relay to an approved terminal block to be furnished by the customer. The terminal block shall be located in a lockable junction box mounted adjacent to (but not within) the Company metering compartment and not on the face of the Company metering panel.

4. The customer will be required to make a non-refundable contribution in aid of construction to Company for the requested meter(s) installation. The non-refundable contribution amount will be determined at the time of the request as follows:

   4.1 If a meter currently exists on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less the equipment cost of Company's existing meter.

   4.2 If a meter has not been installed on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less 100% of the AUC cost of a Company standard meter.

   4.3 If a specialized meter is existing on a customer's site and the customer requests an upgrade to a different type of meter, the customer will be responsible for 100% of the cost (installation and equipment) associated with the requested meter.

   Company will not place an order for a requested meter(s) until payment has been received from the customer. The typical lead time for procurement of meters is six (6) to eight (8) weeks. Once the requested meter(s) have been received, Company will schedule the installation of the meter(s) with the customer or a designated representative.

   Company will retain ownership of all meters and Company installed metering equipment.

   If a customer makes a nonrefundable contribution for the installation of a specialized meter and then terminates service or requests Company to remove and/or replace the specialized meter, the customer will not be eligible for a refund.

Company will provide general maintenance of the specialized meter; however, in the event the meter should become damaged, obsolete or inoperable, the customer will be responsible for 100% of the replacement cost (installation and equipment) associated with the specialized meter.

Company will not be responsible for the installation, maintenance, or usage fees associated with any phone lines or related communication equipment.

5. Under no circumstances shall the customer stop the operation or in any way affect or interfere with the operation of the isolation relay and the related output wiring. The integrity of Company's billing metering equipment within the sealed metering compartment shall be maintained.

6. Company reserves the right to interrupt the specialized metering circuit for emergencies or to perform routine or special tests or maintenance on its billing metering equipment, and in so doing assumes no responsibility for affecting the operation of the customer's demand control or other equipment. However, Company will make a good faith effort to notify the customer prior to any interruption of the specialized metering circuit.

7. The possible failure or malfunction of an isolation relay and subsequent loss of kWh contact closures to the customer's control equipment shall in no way be deemed to invalidate or in any way impair the accuracy and readings of Company's meters in establishing the kWh and demand record for billing purposes.

8. The accuracy of the customer's equipment is entirely the responsibility of the customer. Should the customer's equipment malfunction, Company will reasonably cooperate with the customer to the extent of assuring that no malfunction exists in Company's equipment. Work of this nature will be billed to the customer, unless the actual source of the malfunction is found within Company's equipment.

9. If Company provides pulse values in kWh, customer's equipment must be capable of readjustment or recalibration to adjust to new contact closure values and rates should it become necessary for Company to adjust the pulse values due to changes in Company's equipment.

10. No circuit for use by the customer shall be installed from Company's billing metering potential or current transformer secondaries.

11. Company reserves the right, without assuming any liability or responsibility, to disconnect and/or remove the pulse delivery equipment at any time upon 30 days written notice to the customer.

12. Upon request by Company, the customer shall make available to Company monthly load analysis information.

13. References to electric kWh pulses above shall mean isolation relay contact closures only; the customer is required to furnish operating voltage service. Isolation relay contacts are rated 5 amps, 28 volts DC or 120 volts AC.

14. The customer assumes all responsibility for, and agrees to indemnify and save Company harmless against, all liability, damages, judgments, fines, penalties, claims, charges, costs and fees incurred by Company resulting from the furnishing of specialized metering.

15. A waiver at any time by either party, or any default of or breach by the other party or any matter arising in connection with this service, shall not be considered a waiver of any subsequent default or matter.

16. Prior written approval by an authorized Company representative is required before electric kWh pulses service may be implemented.

SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION OF SPECIALIZED METERING

Arizona Public Service Company (Company) ~~Electric KWH pulses~~ will ~~be~~ provided specialized metering upon customer request, provided ~~by Company if Customer's billing metering equipment is of the type dependent on pulses proportional to KWH to drive the demand meter, and~~ the c~~C~~ustomer agrees to the following conditions:

1. ~~Company will provide electric KWH pulses to Customer who can demonstrate the capability of using such KWH pulses for the purposes of load shaping.~~ The customer must contact their Company Account Representative to request and coordinate the purchase and installation of specialized metering such as KYZ pulse meters, IDR meters, or IDR and KYZ pulse meters. The customer must specify whether a modem will be required.

2. ~~Customer shall submit a plan and wiring diagram for the proposed use of the electric KWH pulses for prior approval by Company's Electric Meter Section.~~ If the customer requests a meter with a modem option, the customer will be required to install communication equipment and connections which shall include a RJ11 or RJ12 jack. A coil of communication cable with either an RJ11 or RJ12 jack is to be provided within five to ten feet of the meter panel location and in such a manner that will provide for ease of attachment of the jack to the meter panel by Company. The phone line must be installed prior to the installation of the meter. The customer must provide Company with a phone number and any other communication access information to the meter(s) prior to Company installation of the meter(s).

3. ~~The Company (through its Electric Meter Section) shall furnish, install and maintain:~~ If a customer requests kWh pulses, Company shall furnish an isolation relay and maintain the output wire and connections from this relay to an approved terminal block to be furnished by the customer. The terminal block shall be located in a lockable junction box mounted adjacent to (but not within) the Company metering compartment and not on the face of the Company metering panel.

   ~~3.1 The isolation relay, in connection with providing KWH pulses, in the billing metering compartment of the service entrance switchboard, and~~

   ~~3.2 The output wires and connections from this relay to an approved terminal block to be furnished by Customer. The terminal block shall be located in a lockable junction box mounted adjacent to (but not within) Company metering compartment and not on the face of Company metering panel.~~

4. ~~Customer shall pay the complete installation cost of the isolation relay and output wiring as set forth above, as a non-refundable contribution.~~ The customer will be required to make a non-refundable contribution in aid of construction to Company for the requested meter(s) installation. The non-refundable contribution amount will be determined at the time of the request as follows:

   4.1 If a meter currently exists on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less the equipment cost of Company's existing meter.

   4.2 If a meter has not been installed on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less 100% of the AUC cost of a Company standard meter.

   4.3 If a specialized meter is existing on a customer's site and the customer requests an upgrade to a different type of meter, the customer will be responsible for 100% of the cost (installation and equipment) associated with the requested meter.

CONCEPTUAL DRAFT FOR DISCUSSION PURPOSES

Company will not place an order for a requested meter(s) until payment has been received from the customer. The typical lead time for procurement of meters is six (6) to eight (8) weeks. Once the requested meter(s) have been received, Company will schedule the installation of the meter(s) with the customer or a designated representative.

Company will retain ownership of all meters and Company installed metering equipment.

If a customer makes a nonrefundable contribution for the installation of a specialized meter and then terminates service or requests Company to remove and/or replace the specialized meter, the customer will not be eligible for a refund.

Company will provide general maintenance of the specialized meter; however, in the event the meter should become damaged, obsolete or inoperable, the customer will be responsible for 100% of the replacement cost (installation and equipment) associated with the specialized meter.

Company will not be responsible for the installation, maintenance, or usage fees associated with any phone lines or related communication equipment.

5. Under no circumstances shall the c~~C~~ustomer stop the operation or in any way affect or interfere with the operation of the isolation relay and the related output wiring. The integrity of Company's billing metering equipment within the sealed metering compartment shall be maintained.

6. Company reserves the right to interrupt the specialized metering~~pulse~~ circuit for emergencies or to perform routine or special tests or maintenance on its billing metering equipment, and in so doing assumes no responsibility for affecting the operation of the c~~C~~ustomer's demand control or other equipment. However, Company will make a good faith effort to notify the c~~C~~ustomer prior to any interruption of the ~~pulse~~ specialized metering circuit.

7. The possible failure or malfunction of an isolation relay and subsequent loss of ~~KWH~~ kWh contact closures to the c~~C~~ustomer's control equipment~~,~~ shall in no way be deemed to invalidate or in any way impair the accuracy and readings of Company's meters in establishing the ~~KWH~~ kWh and demand record for billing purposes.

8. The accuracy of the c~~C~~ustomer's ~~impulse totalizer and demand control~~ equipment is entirely the responsibility of the c~~C~~ustomer. Should the c~~C~~ustomer's equipment malfunction, Company will reasonably cooperate with the c~~C~~ustomer to the extent of assuring that no malfunction exists in Company's equipment. Work of this nature will be billed to the c~~C~~ustomer, unless the actual source of the malfunction is found within Company's equipment.

9. If Company provides~~The~~ pulse values in ~~KWH~~ kWh, ~~provided by Company will be those in use by Company's billing metering system.~~ c~~C~~ustomer's equipment must be capable of readjustment or recalibration to adjust to new contact closure values and rates~~,~~ should it become necessary for Company to adjust the pulse values due to changes in Company's equipment.

10. No circuit for use by the c~~C~~ustomer shall be installed from Company's billing metering potential or current transformer secondaries.

11. Company reserves the right, without assuming any liability or responsibility, to disconnect and/or remove the pulse delivery equipment at any time upon 30 days written notice to the c~~C~~ustomer.

SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION OF SPECIALIZED METERING

12. Upon request by Company, the c~~C~~ustomer shall make available to Company monthly load analysis information ~~showing the effect of Customer's load regulation~~.

13. References to electric ~~KWH~~ kWh pulses above shall mean isolation relay contact closures only; the c~~C~~ustomer is required to furnish operating voltage service. Isolation relay contacts are rated 5 amps, 28 volts DC or 120 volts AC.

14. The c~~C~~ustomer assumes all responsibility for, and agrees to indemnify and save Company harmless against, all liability, damages, judgments, fines, penalties, claims, charges, costs and fees incurred by Company resulting from the furnishing of ~~electric KWH pulses by Company on Customer's side of the isolation relay~~specialized metering.

15. A waiver at any time by either party, or any default of or breach by the other party or any matter arising in connection with this service, shall not be considered a waiver of any subsequent default or matter.

16. Prior written approval by an authorized Company representative is required before electric ~~KWH~~ kWh pulses service may be implemented.

CONCEPTUAL DRAFT FOR DISCUSSION PURPOSES

EXHIBIT
APS-12
admitted

BEFORE THE
ARIZONA CORPORATION COMMISSION

TESTIMONY OF

KENNETH GORDON, Ph.D.

ON BEHALF OF

ARIZONA PUBLIC SERVICE COMPANY

June 27, 2003

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I. QUALIFICATIONS, SUMMARY AND CONCLUSIONS

Q. Please state your name and business address.

A. My name is Dr. Kenneth Gordon. I am a Special Consultant with National Economic Research Associates, Inc. ("NERA"), One Main Street, Cambridge, MA 02142. Previously, I was a Senior Vice President at NERA. My Curriculum Vitae is attached to this testimony as Appendix A..

Q. Please state your qualifications.

A. I am an economist and former Chairman of both the Maine Public Utilities Commission ("Maine PUC") and the Massachusetts Department of Public Utilities ("Mass. DPU").[1]

I have been an economist since 1965, and I have been directly involved with developing and establishing regulatory policy at the federal and state levels since 1980, when I became an industry economist at the Federal Communications Commission ("FCC").

I received my A.B. degree from Dartmouth College in 1960. I received my M.A. degree in 1963 and my Ph.D degree in 1973, both in economics, from the University of Chicago. I have taught applied microeconomics, industrial organization, and regulation (as well as other subjects) at Georgetown University, Northwestern University, University of Massachusetts at Amherst, and Smith College.

From 1980 to 1988, I was an industry economist at the FCC's Office of Plans and Policy, where I worked on a full range of regulatory issues, including telecommunications, cable, broadcast, and intellectual property rights. At the FCC, a major focus of my work was on activities aimed at introducing competition into communications markets.

Prior to joining NERA in November 1995, I chaired the Maine PUC (1988 to December 1992) and then the Mass. DPU (January 1993 to October 1995). During my term as chairman of the Mass. DPU, the DPU investigated and approved a price cap incentive regulation plan for NYNEX (now part of Verizon Corporation), and also undertook a

[1] The Mass. DPU is now known as the Massachusetts Department of Telecommunications and Energy.

proceeding to examine interconnection and other issues related to the development of competition at all levels of telecommunications, including basic local service.

While I was its Chairman, the Mass. DPU issued a series of orders aimed at the reform of electric rate regulation, including revisions to integrated resource management procedures, the introduction of incentive regulation, policy issues related to the regulatory treatment of mergers and acquisitions, and the design of electric industry restructuring. I was heavily involved in developing Massachusetts' plan to introduce competition in retail electric markets in that state, and the concurrent efforts to establish practical policies to address stranded costs and other transitional issues that arise in restructuring the electric utility industry. While in Massachusetts, I co-chaired the Governor's task force on electricity competition.

While a regulator, I was active in the National Association of Regulatory Utility Commissioners ("NARUC"), serving on its Communications and Executive Committees. In 1992, I served as President of NARUC. I was also Chairman of the BellCore Advisory Committee and the New England Governor's Conference Power Planning Committee.

Q. **Please describe the overall situation in which, in your opinion, Arizona Public Service Company ("APS" or the "Company") finds itself, and the consequences of that position.**

A. There are five points to emphasize. First, in spite of the fact that its market is open to choice at the retail level, in a practical sense APS continues to have, in its traditional service territory, obligations to serve customers, whether as provider of last resort ("POLR) or otherwise, that are similar to those it had while operating on a sole-provider basis. It must provide safe and reliable power to its customers, in as efficient a manner as reasonably possible. Second, and closely related to this, APS remains a traditional utility from a ratemaking perspective, with its rates regulated based on traditional rate-of-return-regulation/cost of service principles. While APS' rates have been modified in the past several years by price reductions and/or freezes agreed to through a negotiated process, and approved by the Arizona Corporation Commission ("Commission"), the underlying process for setting its rates, along with other terms and conditions of service, remains the same. Third, Arizona's regulatory framework must allow APS sufficient flexibility to meet its basic responsibilities of providing reliable power, even as the Commission continues to explore other possible configurations of the industry in the state. Fourth, the Company has experienced unanticipated turns in the regulatory policies that govern it. These reversals of policy could threaten the ability of APS to satisfactorily meet its obligations to its customers unless the Commission addresses the impacts of its policy reversal in a timely and responsible manner. Finally, while the central focus of regulatory policies should be on consumers, careful attention to investors' interests is an essential part of that process and, if done properly, is directly aligned with long-term consumer interests.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to help provide a policy framework for properly regulating APS in the circumstances that utility is in today. As an economist and former Chairman of two state regulatory commissions, I discuss some basic principles of regulation and indicate how they are relevant in the circumstances now faced by APS.

The Commission has moved in the direction of competition in electric generation, although this movement has slowed given recent changes in its regulatory policy, conditions in Western energy markets, and capital markets. Nevertheless, on the federal level (and in many states as well), regulators continue to focus on developing regulatory policies that support competition in generation, while continuing to regulate transmission (and, at the state level, distribution) as natural monopolies. As the Commission is well aware, there is less uniformity in policies with respect to retail competition.

The rate case proceeding that APS is filing is the "next step" in an emerging regulatory process that has already undergone a sharp change in direction with respect to the ownership of generation, but has yet to set a firm new course. In its decision in this proceeding, the Commission faces a number of important questions and, in particular, will have to deal with the consequences of having reversed an important element of its regulatory policies. The Commission will also have to decide where it wants APS to go from here, keeping in mind that APS cannot be an efficient and reliable service provider if it is expected to be "all things to all people," and that APS must have the financial and economic capability needed to accomplish its mission. My goal, in offering these policy recommendations, is to identify and provide an analysis of critical regulatory issues raised by the Commission's recent Orders. It is important to note that my conclusions and comments are based on circumstances that are specific to the situation that the Commission, APS, and APS' customers face in Arizona, and may or may not be applicable to other situations.

Going forward, it is important that regulatory policies be carried out in such a way as to provide APS with the means to provide efficient, safe, adequate, and reliable service to customers. As part of the process, APS should have an opportunity to recover its reasonable costs of providing service, including its allowed cost of capital. In other words, regulatory policies need to allow APS to keep the "lights on" as efficiently as possible. The focus should be on efficiency and consumer benefits—and APS must be able to raise capital when needed at reasonable prices if these goals are to be achieved.

Q. Please describe the special features of the competitive/regulatory situation in Arizona with respect to APS.

A. The Commission has recently begun to re-frame the policy framework under which the Company operates. The Track A Order[2] reverses the Commission-ordered transfer of APS' generation assets to a separate corporate affiliate, thereby disrupting the balancing of interests contained in the 1999 Settlement Agreement, which included: (1) a significant write-off of regulatory assets by the Company; and (2) a series of substantial rate decreases for customers.

The Commission's decision to modify its regulatory policies regarding APS' planned transfer of its generation to its non-utility affiliate, Pinnacle West Energy Corporation ("PWEC"), represented a major policy reversal. Foreclosing the transfer of generation

[2] Decision No. 65154 (September 10, 2002).

changed an important component (arguably the most important component) of the 1999 Settlement Agreement for APS, which provided for a complex series of tradeoffs among the interested parties, and had been agreed to by a number of parties and approved by the Commission. APS' current inability to configure its generation operations in a single entity, as originally envisioned, is a particular concern.

The Commission must now determine the proper level of the rates APS charges to its retail customers, using a traditional regulatory process. In addition, the Commission must resolve a number of issues that were left for future determination in earlier proceedings. These include: (1) the proper rate treatment of the PWEC generating assets built within that entity, but which now find themselves operating alone, without the complementary generation of APS that was to have been moved to PWEC to serve APS; (2) the rate treatment of the regulatory assets ($234 million pretax) that had been written off; and (3) the rate treatment of transition costs associated with the planned transfer of generating assets to PWEC.

Q. What conclusions have you drawn?

A. I have drawn the following conclusions:

- *The regulatory compact assures investors of fair and reasonable treatment, and thereby helps ensure reasonably priced capital.* Given the basic financial fact of life that if the utility is to meet its service obligations, it must have a meaningful opportunity to recover its just and reasonable costs of doing business, including the cost of capital, regulators are obligated to treat the utility and its owners reasonably. Importantly, this is also beneficial to the utility's ratepayers in the longer term because it helps to moderate the utility's cost of capital and allows it the financial strength to invest in service quality and reliability. Regulators should strive to act in a way that minimizes the regulatory risks to investors and compensates them for that risk.

- *In the current environment, utilities, such as APS, face significant risks, particularly regulatory ones.* This is especially true, of course, when regulators feel they should be making changes in regulatory policies. However, once a regulatory agency re-sets its direction, it must move forward in a way that treats the utility in a reasonable manner prospectively and which "settles up" the costs reasonably incurred in reliance upon the "old" policy. Over the longer term such equitable treatment will benefit customers as well.

- *The Commission needs to address the consequences stemming from its decision to halt divestiture.* As applied to this case, the above conclusions mean that the Commission must properly address: (1) the bifurcation of APS generation between itself and its affiliate, PWEC; (2) recovery by APS of the full costs of preparing for such divestiture; and (3) the restoration of the $234 million pretax write-off that APS took in reliance on the 1999 Settlement Agreement with the Commission.

- *Continued vertical integration is a reasonable approach, especially for a utility that is in APS' situation.* While it is clear that FERC and many states are pursuing regulatory policies and industry structures that accommodate wholesale competition, this goal can be accomplished while preserving the vertical economic efficiencies and stability that vertical integration can provide.

Q. How is your testimony organized?

A. **Section II** briefly summarizes the history of electricity policy in Arizona as it pertains to the Company and its customers. Important considerations include the regulatory compact in Arizona (including the terms of the 1999 Settlement Agreement) and the events of the last few years in nearby California and the broader Western power markets. The conclusions that I draw in this testimony take these factors into account and are therefore specific to APS' situation (and that of Arizona generally).

Section III discusses the regulatory compact, regulatory risk, and appropriate regulatory policy when the "rules of the game" are changed. Proper regulation is needed to accommodate wholesale competition, which can be accomplished while maintaining organizational efficiency. As the Commission deals with the effects of its Track A decision, it is very important that the Commission aim to achieve allocative efficiency (where utility rates are set in a way that reflects its economic costs), while also providing the utility with proper opportunities and incentives to achieve productive (technical) efficiency and make the investments that are critical to maintaining reliability over time. The ability of a regulated utility to consistently attract capital is largely a function of the confidence that investors have in a jurisdiction's regulatory compact and therefore it is critically important that prudence and related issues pertaining to new generating units be addressed in a reasonable manner.

Section IV addresses the nature and potential benefits of vertical integration in the current environment. It also discusses the link between vertical integration and the regulatory compact. I explain why it is important that utilities have the flexibility to achieve organizational efficiency, and I explain that vertical integration is a reasonable way to achieve that goal. I also explain that the meaning of vertical integration has changed with the movement to wholesale competition, which, in particular, requires changes in how transmission is organized and operated.

II. A BRIEF HISTORY OF THE RELEVANT ARIZONA CIRCUMSTANCES

Q. Please describe your understanding of electric policy in Arizona, as it pertains to APS.

A. While the purpose of my testimony is to provide a policy framework for properly regulating the Company in today's circumstances in Arizona, it is important to briefly describe the circumstances APS finds itself in today.

In the U.S., there has been a general movement toward wholesale (and, in some states, retail) competition, going back at least as far as the Energy Policy Act of 1992 ("EPAct") and the Federal Energy Regulatory Commission's ("FERC") Orders Nos. 888 and 889. The FERC continues to be committed to enabling the development of competitive wholesale power markets.[3] In Arizona, the movement to retail (and wholesale) competition has been complicated by institutional and infrastructure circumstances in the state (*e.g.*, the large amount of transmission and generation that is owned by public power entities), as well as transmission limitations.

For APS, the 1999 Settlement Agreement, as approved by the Commission, has provisions for: (1) a series of retail rate decreases for residential, commercial, and industrial customers, and the development of rates to accommodate competitive direct access service; (2) a moratorium (under almost all circumstances) on price increases for standard-offer and unbundled competitive direct access service until July 1, 2004; (3) a

[3] In its press release announcing its issuance of a white paper on bulk power market design, the FERC emphasized its "strong commitment to customer-based, competitive wholesale power markets, while underscoring an increasingly flexible approach to regional needs and outlining step-by-step elaborations of its key market design proposal." FERC, "Commission introduces White Paper on bulk power market design, focuses on RTOs while citing deference to regional needs," Docket No. RM01-12-000, April 28, 2003.

write-off of regulatory assets with a current value of $234 million; (4) deferral provisions for certain other costs; (5) APS' distribution system was opened for retail access without legal challenge by APS; (6) recovery of some (but not all) potentially stranded costs through a competitive transition charge that remains in place until December 31, 2004; and (7) the transfer of competitive generation assets to a non-utility affiliate at book value no later than December 31, 2002.

As is typically the case in regulatory resolutions of this type, the settlement reached by the parties was intended to be taken as a whole, in order to preserve the tradeoffs that had been made among the parties to achieve agreement. Further, I understand that the 1999 Settlement Agreement includes language stating that the Commission's electric restructuring rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with that agreement. In fulfilling its part of the agreement, the Company wrote off about $234 million (pretax in 1999) of its otherwise recoverable stranded costs. The Commission approved the Settlement, including the provision that explicitly made the Commission a party to the agreement, thereby agreeing to bind itself to its terms.

The years subsequent to the Commission's approval of the 1999 Settlement Agreement were, of course, dramatic ones in nearby California and throughout the broader Western power markets.[4] The California electricity crisis and the broader crisis in Western energy markets during 2000-2001 were major events, with dramatic effects on wholesale electricity markets, the merchant generation industry, and the utilities that generate and/or acquire generation on behalf of their customers, such as APS.[5]

As a result of concerns arising out of these unexpected circumstances, in September 2002, the Commission issued its Track A Order, which reversed its own decision that had required APS to transfer its generation assets to a separate corporate affiliate (a

[4] Banc of America Securities, for example, states that "wholesale power markets have dried up, significantly impairing merchant economics and dislocating the [merchant] business model." Banc of America Securities, *Outlook for the Merchant Energy Sector: Shock Treatment—Is the Merchant Business Model Dead or Alive?*, September 2002, p. 1.

[5] For a survey, *see*: Paul L. Joskow, "California Electric Crisis," *Oxford Review of Economic Policy*, Vol. 17, No. 3, 2001, pp. 365-388.

transaction previously found to be "in the public interest"). The Commission thereby unilaterally modified the 1999 Settlement Agreement, which had authorized APS' transfer of its generating assets, and directed APS to cancel its activities to transfer its generation assets to PWEC (or some other entity).

Q. Where has this left APS and the Commission?

A. APS remains the major electric utility in Arizona with generation, transmission, distribution, and sale functions. Utility regulation of APS continues, with most features of the pre-competitive regulatory world continuing in place. The Commission also, however, remains committed to competition.

This subjects APS to conflicting regulatory and market forces. In particular, APS continues to have an *obligation* to serve those customers who have not switched to a competitive generation provider (as well as those who switch back) even though retail customers can (and might again) switch to competitive suppliers, if they wish to do so.[6] This means that APS has an obligation to plan for customers' future demands and either build or buy the power and energy needed to meet these demands. Given the long lead times and useful lives inherent to utility assets—and the basic fact that the electricity *has* to be there when customers demand it—APS must make significant investments and commitments to meet customer requirements. Thus, APS continues to operate as a (modified) vertically-integrated utility.

III. CONSISTENT REGULATORY COMMITMENT IN AN ERA OF TRANSITION

Q. Has the Commission changed its policy with respect to APS' divestiture of generation?

A. Yes. As previously discussed, the Track A Order modified the 1999 Settlement Agreement, which authorized APS' transfer of its generating assets, and specifically

[6] Retail customers can, in principle, choose to take service from a competitive provider, although few (if any) competitors are offering retail service in Arizona at the present time.

directed the Company to cancel its activities aimed at transferring its generation assets to PWEC. While I do not comment on the Commission's reasons for this change in policy, given the circumstances it faced when it did so, the Commission decision left open a number of questions that need to be resolved, and left undone steps that need to be taken. In December 2002, APS and Commission Staff agreed that it would be appropriate for the Commission to consider some of these matters as part of APS' next rate case proceeding. Among the issues left to be decided were:

1. The rate treatment of the generating assets that PWEC had constructed in the expectation of selling to APS and which APS now proposes to move into the Company's rate base.

2. Appropriate treatment of the $234 million pretax write-off agreed to by APS as part of the 1999 settlement agreement, which was modified by the Track A Order.

3. The appropriate treatment of previously expensed costs incurred by APS in preparation for the previously anticipated, but now thwarted, transfer of generation assets to PWEC.

Given the Commission's Track A Order, careful consideration needs to be given to carrying out these decisions in a way that both treats the utility's investors fairly and protects consumers from a Western wholesale electric market that is currently undeveloped, while accommodating the continued movement toward effective wholesale competition. An appropriate regulatory contract is adaptable and flexible (within reason) but must also continue to provide the utility with appropriate and adequate compensation for its continued service to customers.

A. Utilities and the Regulatory Compact

Q. Please briefly explain the basic economic features of the public utility industry.

A. The public utility industry is capital-intensive. In order to provide efficient, safe, adequate, and reliable service to their customers, utilities must have uninterrupted access to capital markets to maintain and upgrade capital facilities. Investor-owners of public utilities must submit to the requirements of capital markets to raise money to provide utility services. In other words, investor-owned utilities can only *attract* capital at a reasonable cost by showing that investors' capital will be repaid at a reasonable rate of return through a transparent system of regulated prices. Under traditional rate-of-return regulation, incorporating the traditional regulatory compact, utilities are assured of a reasonable opportunity to recover their prudent, just, and reasonable costs, including the cost of capital.

The historic paradigm whereby vertically-integrated electric utilities with exclusive franchises provide bundled services within distinct franchise service areas has been challenged in recent years. Transmission and distribution ("T&D") system owners have been required to open up access to their networks, allowing competing suppliers of electricity to offer service.

Q. Please elaborate on what you mean when you refer to the regulatory compact?

A. In general terms, the "regulatory compact" is the concatenation of the U.S. Constitution, franchise agreements, federal and state statutes, Commission Rules and Orders, and policy statements. Economists refer to the regulatory compact as an implicit relational contract, meaning that the "regulatory compact" is not written down in the form of an explicit contract; but it is, nonetheless, an intrinsic part of the relationship between the regulated industry on the one hand, and its regulators on the other.

Traditionally, an electric utility, required to operate in the interests of customers, has borne an obligation to provide efficient, safe, adequate, and reliable utility services to customers in return for a "franchise" (or some other means of restricting entry to limit competition) and the opportunity to earn a fair rate of return on its invested capital. Utilities have made long-term commitments in generation to meet the needs of ratepayers adequately and reliably. As a regulated firm, the utility must comply with regulatory accounting requirements, abide by price regulations, meet other regulatory requirements (*e.g.*, affiliate interest rules, customer service rules), invest in facilities to meet customer growth in its service territory, and comply with a host of other requirements. The utility, which has a duty to serve its customers, has substantial expertise in making long-term commitments to assure the adequacy and reliability of the electric grid, and has the responsibility to acquire generating resources, subject to regulatory oversight.

Regulators, acting as an "agent" for customers, seek to ensure that the utility acts prudently and efficiently when providing utility services. Because customers are not fully able to monitor the actions of the utility, regulatory agencies are established to ensure that the utility agent acts in the best interest of customers. Regulators' primary regulatory "tool" for overseeing the utility is the traditional rate-of-return/cost-of-service rate case, which provides the regulator with a forum for investigating and determining the justness and reasonableness of the utility's rates. Using a "test year" revenue requirement, the regulatory agency examines the reasonableness of the utility's sales growth projections, operating expenses, cost of capital, and other cost components, and then sets rates that provide the utility a reasonable opportunity to recover its just and reasonable costs—this is the "heart" of the regulatory compact. While traditional rate regulation does not usually explicitly focus on the utility's incentives to any great extent, other than through disallowances of imprudent costs, traditional rate regulation does provide incentives via "regulatory lag," meaning that once rates are set the utility must control its costs and efficiently meet customers' demand in order to maintain or improve its profitability. Ultimately, through the regulatory process, the utility passes on to customers the benefits of its sole-provider status.

Q. Does the regulatory compact concept apply when, as here, a regulatory agency approves a stipulation?

A. Stipulations are an *explicit* agreement between a utility and the other parties to the settlement agreement. In this case, the Commission both approved and agreed to hold itself to this settlement. In my opinion, the settlement became part of the regulatory compact when it was approved (and joined) by the regulator.

Q. Can a regulator itself unilaterally deviate from the regulatory compact?

A. Not if it expects to retain the confidence of the investment community. A regulator can, of course, alter its own specific rules or other requirements in accordance with whatever procedures are required in that jurisdiction and within the bounds of whatever substantive authority it possesses, but for major changes in requirements that significantly alter previous reasonable expectations, it must compensate the utility for any harm done to it by the change.

This is important both for fairness and economic efficiency reasons. Fairness considerations include meeting the reasonable expectation of investors as to the underlying regulatory structure that they were led to believe would be in place for the utility. Put more colloquially, they were presented with assured "rules of the game." From an economic standpoint, regulation can be viewed as a "highly incomplete form of long-term contracting" in which the terms of the regulatory compact adapt to changing circumstances to meet the needs of customers while also ensuring that the utility has the opportunity to earn a fair rate of return.[7] Fairness requires that costs that are reasonably incurred, but become stranded as a result of change in a regulatory policy should, in recognition of the regulatory compact, be recoverable by the utility. In earlier decisions (such as the 1999 Settlement Agreement), this Commission has recognized this principle.

It is particularly important to remember that the regulatory compact does not allow a regulator to change the regulatory rules without appropriate compensation after investments have been made by the utility in good faith reliance on those rules. The problem for investors is that once investments have been made, they become exposed to opportunistic behavior by the regulator, which economists sometimes refer to as regulatory "recontracting" or "holdup." The regulatory compact evolved, in large part, to prevent opportunistic regulatory behavior because fulfilling investors' reasonable expectations ordinarily is in consumers' long run interest. Efficiency considerations include allocative efficiency (utility rates should be set in a way that reflects economic costs), productive (technical) efficiency (the utility should be able to recover prudent costs aimed at providing efficient utility service in rates), and dynamic efficiency (the utility should aim—over time—to make investments that ensure appropriate levels of

[7] Oliver E. Williamson, *The Economic Institutions of Capitalism* (New York: Free Press, 1985), p. 347.

reliability and increase the efficiency of the utility network). With traditional utility regulation, the upside return to the utility is effectively capped at the allowed ROE, an appropriate policy given the presumed essential nature (sole provider status) of the firm. Given this, both economic efficiency and fairness demand that downside risk be capped as well. The ability of a regulated utility to consistently attract capital is largely a function of the confidence that investors have in a jurisdiction's regulatory compact and therefore it is critically important that prudence issues and the overall returns to investors be addressed in a reasonable manner.

B. The Reversal of the 1999 Settlement Agreement

Q. Does the reversal by the Commission of its approval of the transfer of APS' generation to a non-utility affiliate raise important regulatory policy issues?

A. Yes, it does. The Track A order clearly terminates the Company's plans to move its generation from the utility to a non-utility affiliate. Given this major change in one part of the 1999 Settlement Agreement, the equitable outcome, in principle, might seem to be to restore APS and its affiliates to their *status quo* position in 1999. This, however, is not completely possible—after all, APS has already reduced rates to its customers pursuant to the 1999 Settlement Agreement, and PWEC has borne the burden and risk of constructing new generation for APS. To partially deal with this issue, however, APS is filing a rate case to reunify the PWEC generation at APS under a common regulatory scheme.

In addition, APS wrote-off certain otherwise recoverable costs pursuant to the 1999 Settlement Agreement and then incurred significant additional costs relating to the planned transfer of its generation. Because it was then prohibited from transfering generation to a non-utility affiliate, as a result of the Commission's Track A decision, reasonable regulation, going forward, would restore the assets that had been written off the company's books and allow APS to recover the these assets as part of its revenue requirement. Importantly, so far as I am aware, there has been no finding that these costs were not prudent and reasonably incurred. Further, APS should be able to recover all reasonable costs that it had incurred as a result of the Commission's approval of the plan to transfer its generation assets, including the $234 million of regulatory assets.

Q. Didn't APS agree in the Settlement to forego one-third of the cost of divesting its generation?

A. As I understand it, that was not part of the original agreement. However, I understand that it is also true that APS did not oppose that change in the provisions of the settlement. But it is equally clear that such acquiescence was premised on the divestiture actually taking place as proposed. It would be adding insult to injury to deny APS divestiture but then hold them to the one-third write-off of divestiture-related costs. This would be like the seller backing out of a deal and then refusing to give back the buyer's down-payment.

IV. VERTICAL INTEGRATION, ORGANIZATIONAL EFFICIENCY, AND REGULATION

Q. Has vertical integration been a commonly-used way to achieve organizational efficiency in the electric utility industry?

A. Yes. Vertical integration was—and, in many cases, continues to be—commonplace in the electric services industry (as well as in telecommunications) because it can economize on transaction costs and facilitate effective coordination and cooperation in operating an interconnected system. For example, it can allow unified decision making with respect to generation and transmission. In 1989, Paul Joskow noted that:

> "[t]he combination of economies of scale, multiproduct production, and vertical integration provide the primary public interest rationale for the emergence of vertically integrated utilities with de facto legal monopoly franchises to provide retail service to a specific geographical area, subject to price regulation. . . . regulated integrated monopoly distribution utilities are the efficient institutional response to obtain the cost savings of single-firm production without incurring the costs of monopoly pricing."[8]

[8] Paul L. Joskow, "Regulatory Failure, Regulatory Reform, and Structural Change in the Electrical Power Industry," *Brookings Papers: Microeconomics*, 1989, pp. 139-140.

In the telecommunications industry, the incumbent local exchange carriers ("ILECs") continue to be vertically integrated. In passing the Telecommunications Act of 1996 ("TA 1996"), Congress sought to establish a "pro-competitive, de-regulatory national policy framework" for the United States.[9] Rather than disturbing the organizational structure of the ILECs, TA 1996 focuses on wholesale services that the large ILECs must provide on a nondiscriminatory basis, including interconnection, unbundling, and resale requirements. Simply put, federal and state telecommunications policy has gone down a path of relying on competition and non-structural safeguards to ensure competition, while allowing the ILECs to retain the economies of scale and scope associated with vertical integration.

Q. Please summarize the rationale for why firms (in any industry) may choose to vertically integrate.

A. Vertically-integrated firms emerge when a transaction can be completed most economically through unified ownership (*i.e.*, the buyer and supplier are in the same enterprise). A basic aspect of vertical integration is the "elimination of contractual or market exchanges, and the substitution of internal exchanges within the boundaries of the firm."[10] If vertical integration is chosen over a market exchange relationship, Williamson argues that it must be "because the contract between collocated stages is mediated more effectively by hierarchy than by market."[11] Williamson also notes that vertical integration has "the purpose and effect of economizing on transaction costs."[12] In other words, by achieving economies of scope and scale the utility can increase its productive (technical) efficiency, which benefits customers.

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[9] Joint Explanatory Statement of the Committee of Commerce, H.R. Rep. No. 458, S. Rep. No. 230, 104th Cong., 2d Sess. at 113 (1996). The Federal Communications Commission cited this language in its *Implementation of the Local Competition Provisions of the Telecommunications Act of 1996*, CC Docket No. 96-98, First Report and Order, 11 FCC Rcd 15499, 1996 (Interconnection Order), ¶ 21.

[10] Martin K. Perry, "Vertical Integration: Determinants and Effects," *Handbook Of Industrial Organization: Volume 1*, edited by Schmalensee and Willig (Amsterdam: North-Holland, 1989), at 185.

[11] Oliver E. Williamson, *The Mechanisms of Governance* (New York: Oxford Univ. Press, 1996), p. 16.

[12] *Id.*, p. 85.

Q. Do you have any comments regarding the Commission's decision to require that the Company *not* transfer its generation assets either to an unrelated third party or to a separate corporate affiliate?

A. My view on divestiture of utility generation has been that divestiture cannot be ruled out as a possible policy option and utilities should not be restricted from considering voluntary divestiture of particular assets as one course of action as they decide how best to operate in a restructured (competitive) market. However, my basic view also is that mandatory divestiture should be a last resort as a regulatory policy, to be used only after less interventionist policies (*i.e.*, functional unbundling and codes of conduct) have been tried.

The FERC reached this same conclusion in Order No. 888:

> [w]e believe that functional unbundling, coupled with these safeguards [*i.e.*, codes of conduct] is a reasonable and workable means of assuring that non-discriminatory open access transmission occurs. In the absence of evidence that functional unbundling will not work, we are not prepared to adopt a more intrusive and potentially more costly mechanism—corporate unbundling—at this time.[13]

My primary concern with mandated divestiture and/or separate subsidiary requirements is that it forecloses important opportunities for "organizational efficiency" that can be captured only if firms are free to define and test the effectiveness of their own corporate structures. Stated more simply, it is up to each firm's management to figure out what the best structure is for their particular firm.

Q. Please explain what you mean by organizational efficiency.

A. An aspect of productive efficiency that warrants special mention is "organizational efficiency"—the concept that a firm's essential character is not fixed. The range of activities undertaken by a single firm evolves with opportunities and circumstances, based on an efficiency logic, specific to the firm, which is not always apparent to outside observers. Utilities that are given the flexibility to redefine themselves for

[13] FERC Order No. 888, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Docket Nos. RM95-8-000 and RM94-7-001, April 24, 1996, p. 59. 61 Fed. Reg. 21,540 (1996).

competition have a good chance of surviving, benefiting both consumers and owners in the new environment, while those that are artificially limited in their ability to adapt are less likely to succeed. Thus, I believe it is very important that the Company have flexibility and discretion to organize itself in an efficient way.

Q. Are utilities moving back to a more traditional vertical integration that ignores the existence of competition in wholesale electricity markets?

A. No. The FERC's wholesale competition policies, as set forth in its Orders Nos. 888 and 889, have irrevocably changed the way that utilities operate. FERC's Order 2000, which addresses the continuing formation of RTOs and similar institutions, continues the movement toward wholesale competition. Further, the Arizona Commission's efforts to unbundle rates remain in effect. Given these basic facts, electric utilities would not expect to move back to full old-style vertical integration, but can and do integrate a "new-style" vertical integration into this new reality.

Q. Please explain what you mean by "new-style" vertical integration.

A. A new-style vertically-integrated utility can have generation, transmission, distribution, and sale functions but the "lines of demarcation" between these functions will be much clearer than they were when traditional utility vertical integration was the norm. Regulatory rules and institutional structures to support wholesale (and, perhaps, retail) competition in the generation business will be put in place. In the near term, this basically requires implementing a workable transmission structure for the Southwest, via the WestConnect independent transmission group.

"New-style" vertically-integrated utilities, operating in competitive wholesale generation markets, will develop a least-cost mix of owned generation, contracts, and market purchases. By having the flexibility to do this, they can capture the "organizational efficiency" benefits to which I previously referred, hedge customer exposure to the market, and yet take advantage of market opportunities and market efficiencies.

Q. How does vertical integration provide benefits to utilities that have an obligation to serve?

A. The basic point here is that vertical integration can provide a physical hedge to provider-of-last-resort risk. In other words, it reduces the utilities' exposure to markets or contracts in providing provider-of-last-resort service to customers. This is especially important given the turbulence in energy markets in recent years and the current low-volume state of Western energy markets. Given the current state of wholesale market development in the West and the financial troubles that some merchant generators have faced in recent years,[14] vertical integration is a reasonable way for a utility to protect its customers from volatile wholesale electricity prices. Regulators, of course, need to assure that vertically-integrated utilities are regulated in such a way as to accommodate the development of competitive wholesale electricity markets.

Q. Can such "new-style" vertically-integrated utilities co-exist with regulation and the regulatory compact?

A. Absolutely. Vertical-integrated utilities have long been regulated under the regulatory compact. In the new environment, vertically-integrated utilities' rates have been unbundled and functional separation has occurred at FERC, which allows traditional regulation to ensure that the public interest is met while accommodating wholesale competition in the generation market.

Q. Regarding competition in the wholesale market, can "new-style" vertically-integrated utilities co-exist with the new competitive environment?

A. Yes. In fact, even the "old-style" vertically-integrated utilities operated in what were at least partially competitive markets for many years. What FERC and certain state policies have done is to expand those competitive market opportunities by removing obstacles to competition. With the clear lines of demarcation of function that I discussed earlier, and appropriate codes of conduct, vertically-integrated utilities can

[14] Banc of America Securities points out that "[t]he capital markets are essentially closed to the cash strapped merchant players, further heightening the risk that these players will not be able to refinance an estimated $30 billion in debt refinancings over the next two years." Banc of America Securities, *Outlook for the Merchant Energy Sector: Shock Treatment—Is the Merchant Business Model Dead or Alive?*, September 2002, p. 1.

serve an important role in such a competitive wholesale market without abandoning the consumer protections inherent in traditional regulation.

Q. Do you have any concluding comments?

A. Yes. Unification of the PWEC generation into a vertically-integrated APS has efficiency-related advantages. Moreover, it would be not be inconsistent with the broader move toward more competition in the wholesale market and would be an important final step in resolving the fallout from the Track A order. It does so in a manner that makes APS and its affiliates whole, or at least significantly closer to whole, for this change in Commission direction and is thus fully consistent with the regulatory compact as I have described it.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A

DR. KENNETH GORDON

BUSINESS ADDRESS

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Cambridge, MA 02142
617-621-0444

Dr. Kenneth Gordon, as of April 2001, is a Special Consultant with National Economic Research Associates, Inc. specializing in utility regulation and related issues. Prior to that date, Dr. Gordon was a Senior Vice President with National Economic Research Associates. He was Chairman of the Massachusetts Department of Public Utilities from January 1993 to October of 1995. He came to the Massachusetts Commission from the Maine Public Utilities Commission, where he held the office of Chairman from 1988 through the end of 1992. Prior to that, he was an Industry Economist at the Federal Communications Commission's Office of Plans and Policies. Prior to that, he taught at several colleges since 1965, the most recent position having been at Smith College.

Dr. Gordon was an active member of the National Association of Regulatory Utility Commissioners (NARUC) and served as president of that organization in 1992. He was also a member of the Executive Committee, and the Committee on Communications of NARUC. He has served as Chairman of the New England Conference of Public Utilities Commissioners Telecommunications Committee, and is a former Chairman of the Power Planning Committee of the New England Governors' Conference. He currently also serves on several boards and committees. Dr. Gordon has authored a number of publications and lectures widely on topics related to utility regulation.

Dr. Gordon is a graduate of Dartmouth College and holds a doctorate in economics from the University of Chicago.

EDUCATION

University of Chicago	Ph.D	1973
University of Chicago	M.A.	1963
Dartmouth College	A.B.	1960

EMPLOYMENT

April 2001 -	**National Economic Research Associates, Inc.,** Cambridge, MA Special Consultant
August 1996 – March 2001	**National Economic Research Associates, Inc.,** Cambridge, MA Senior Vice President
November 1995 – July 1996	**National Economic Research Associates, Inc.,** Washington, D.C. Senior Vice President
October 1995	**Consulting Economist**
January 1993 - October 1995	**Massachusetts Department of Public Utilities** Chairman
October 1988- December 1992	**Maine Public Utilities Commission** Chairman
1980 - 1988	**Federal Communications Commission, Office of Plans and Policy** Industry Economist
1965 - 1980	**University and College Teaching** (most recently at Smith College)
1963 - 1964	**University of Chicago** Research Associate

CURRENT APPOINTMENTS AND MEMBERSHIPS

Telecommunications Policy Research Conference
Chair, 1995-1996
Board Member, 1994

Energy Modeling Forum (EMF 15, A Competitive Electricity Industry),
Stanford University
Member

American Economic Association

Transportation and Public Utilities Group, AEA

PAST APPOINTMENTS AND MEMBERSHIPS

National Association of Regulatory Utility Commissioners
Communications Committee, 1990 - 1995
Executive Committee, 1991-1995
President, 1992

New England Conference of Public Utility Commissioners
Power Planning Committee
Chairman

Governor's Electric Utility Market Reform Task Force
Co-Chairman

Boston University Telecommunications Forum
Advisor

Center for Public Resources, Legal Program to Develop Alternatives to Litigation
Chairman, Utilities Committee

Office of Technology Assessment, Advisory Panel on International Telecommunications Networks

Bellcore Advisory Committee,
Member and Chairman, 1993 to 1996.

ACTIVITIES

Participant in numerous regional and state committees, organizations, and task forces.

Participant in various NARUC/DOE conferences on gas and electricity issues.

Frequent speaker on electric, telephone and environmental issues nationally.

TESTIMONIES

Before the New York State Public Service Commission, on behalf of Rochester Gas & Electric Company, direct testimony regarding the determination of merger-enabled savings. May 16, 2003.

Before the Connecticut Department of Public Utility Control, on behalf of Connecticut Natural Gas Corporation and the Southern Connecticut Gas Company, Docket Nos. 99-09-03PH02, 99-04-18PH03 and 01-04-04, direct testimony regarding the determination of merger-enabled gas cost savings. April 28, 2003.

Before the Iowa Utilities Board, on behalf of Iowa Telecommunications Services, Inc., rebuttal testimony regarding economic support of the company's rate adjustment proposal. August 6, 2002.

Before the Public Utilities Commission of Ohio, on behalf of the Cincinnati Gas & Electric (Company), Case No. 00-813-EL-EDI and 01-2053-EL-ATA, direct testimony on the imposition of a moratorium on minimum stay requirements with respect to switching between default (POLR) service and competitive service. Filed June 4, 2002.

Before the Iowa Utilities Board, on behalf of Iowa Telecommunications Services, Inc., direct testimony regarding economic support of the company's rate adjustment proposal. May 24, 2002.

Before the Florida legislature, on behalf of Bell South (Florida), oral testimony on rate rebalancing issues in telecommunications. Presented on January 30, 2002.

Before the Public Utilities Subcommittee of the Maryland House Environmental Matters Committee, on behalf of Southern Maryland Electric Cooperative and Choptank Electric Cooperative, testimony on affiliate issues relating to cooperatives' participation in non-core markets. Filed January 22, 2002.

Before the Indiana Utilities Regulatory Commission on behalf of Citizens Gas & Coke Utility and Indiana Gas Co., Inc., Case Nos. 37394GC50S1 and 37399GC50S1. Affidavit on why the use of RFP bids as a transfer price is appropriate. Filed December 10, 2001.

Before the Alberta Energy & Utilities Board, on behalf of EPCOR Transmission Inc., rebuttal testimony addressing code of conduct issues. November 2, 2001.

Before the Illinois Commerce Commission on behalf of Commonwealth Edison Company, Docket No. 01-0423, surrebuttal testimony on designing delivery service tariffs in a way that support economic efficiency. October 24, 2001.

Before the Illinois Commerce Commission on behalf of Commonwealth Edison Company, Docket No. 01-0423, rebuttal testimony on designing delivery services in a way that supports economic efficiency. September 18, 2001.

Before the Alberta Energy & Utilities Board, on behalf of Atco Group of Companies, Affiliate Proceeding Before the Alberta Energy and Utilities Board, Testimony of Rebuttal Evidence, submitted August 3, 2001

Before the Massachusetts Department of Telecommunications and Energy, on behalf of Berkshire Gas Company, direct testimony on benefits of incentive ratemaking and policy rational supporting company's plan. July 17, 2001.

Before the New Jersey Board of Public Utilities on behalf of Verizon New Jersey, Surrebuttal Testimony on structural separation and code of conduct issues (Docket No. TO01020095). Filed June 15, 2001 (panel testimony co-sponsored by C. Lincoln Hoewing).

Rebuttal Testimony on behalf of Qwest Corporation, Application of Authority to provide in-region interLATA service (Docket No. INU-00-2). Filed May 23, 2001.

Before the State of New York State Public Service Commission on behalf of Verizon New York (Case No. 00-C-1945): Initial panel testimony on the New York State competitive marketplace. May 15, 2001 (co-sponsored with William E. Taylor).

Before the Commonwealth of Kentucky Public Service Commission on behalf of E.ON AG, Powergen plc, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company, (Case No. 2001-104). Direct testimony on the benefits to consumer's resulting from the acquisition of Powergen by E.ON AG. May 14, 2001.

Before the New York State Public Service Commission on behalf of New York State and Gas Corporation, Affidavit on the proper treatment of proprietary competitive information by regulators. Affidavit filed April 23, 2001.

Before the Virgin Islands Public Services Commission, Government of the Virgin Island of the United States (PSC Docket No. 526) on behalf of Innovative Telephone, Rebuttal testimony regarding rural exemption, request for interconnection for Innovative Telephone. Filed April 10, 2001.

Before the State of New York Public Service Commission on behalf of Energy East Corporation, RGS Energy Group, Inc., New York State Electric & Gas Corporation, Rochester Gas and Electric Corporation, and Eagle Merger Corp. Affidavit filed March 23, 2001.

Before the Indiana Utility Regulatory Commission on behalf of PSI Energy, Inc. (IURC Docket No. 41445-S1): Rebuttal testimony on the continued use of a purchased power tracker. Filed February 8, 2001.

Before the Pennsylvania Public Utility Commission on behalf of Verizon PA: Rebuttal testimony on why the structural separation model used in electricity does not apply to telecommunications. October 30, 2000.

Before the State of New York Public Service Commission on behalf of New York State Electric & Gas Corporation (Case 96-E-0891): Rebuttal testimony on market power analyses used in setting the backout credit. October 30, 2000. (Cosponsored with David Kathan.)

Before the Connecticut Department of Public Utility Control, on behalf of Connecticut Natural Gas Corporation (Docket No. 99-09-03, Phase II): Rebuttal testimony on role of incentive ratemaking. October 11, 2000.

Before the New York Public Utilities Commission on behalf of New York State Electric & Gas Corporation (Case 96-E-0891): Direct testimony on whether the backout credit set in a stipulation continues to be proper. October 4, 2000. (Cosponsored with David Kathan.)

Before the Virginia State Corporation Commission on behalf of Appalachian Power d/b/a/ American Electric Power Company (Docket Case No. PUA980020): Direct testimony regarding use of "asymmetric" transfer price rules. Filed September 20, 2000.

Before the Alberta Energy and Utilities Board, on behalf of ATCO Gas, ATCO Pipelines, and ATCO Electric: Direct testimony addressing affiliate issues. August 31, 2000.

Before the Iowa Utilities Board on behalf of Qwest Corporation (Docket No. INV-00-3): Direct testimony on deregulation of local directory assistance services. August 11, 2000.

Before the Connecticut Department of Public Utility Control on behalf of the Southern Connecticut Gas Company (Docket No. 99-04-18, Phase III): Late-filed Exhibit No. 159 (direct testimony) on the proper design of an incentive ratemaking plan. August 11, 2000.

Before the Connecticut Department of Public Utility Control on behalf of Connecticut Natural Gas Corporation (Docket No. 99-09-03 Phase II): Prefiled supplemental testimony addressing incentive rate-making issues. Filed August 11, 2000.

Before the Maine Public Utilities Commission on behalf of Central Maine Power Company. Surrebuttal testimony regarding the proper role of incentive ratemaking. August 10, 2000.

Before the Pennsylvania Public Utility Commission on behalf of Bell Atlantic PA (now Verizon PA): Direct testimony on the costs and problems with structural separation in telecommunications. June 26, 2000.

Before the Maine Public Utilities Commission on behalf of Central Maine Power Company (Docket No. 99-666): Rebuttal testimony on incentive rate-making issues. Filed June 22, 2000.

Before the Connecticut Department of Public Utility Control, The Southern Connecticut Gas Company Bench Request/Late file Exhibit (direct testimony) on proper implementation of incentive ratemaking. May 24, 2000.

Before the Public Utilities Commission of Ohio, on behalf of the Cincinnati Gas & Electric Company (Case No. 99-1658-EL-ETP): Supplemental testimony addressing shopping incentive and market power issues. Filed May 1, 2000.

Before the New York Public Service Commission on behalf of New York State Electric & Gas Corporation (NYSEG). Affidavit on the proper calculation of the billing credit customers would receive that switch. Filed April 20, 2000.

Before the Public Utilities Commission of Ohio, on behalf of the Cincinnati Gas & Electric Company: Direct testimony addressing shopping incentive and market power issues. Filed December 28, 1999.

Before the Federal Communications Commission, on behalf of Virgin Islands Telephone: Comments addressing Federal universal service support in the U.S. Virgin Islands. Filed December 19, 1999.

Before the Connecticut Department of Public Utility Control, on behalf of Connecticut Natural Gas Corp.: Direct testimony on performance based ratemaking. Filed November 8, 1999.

Before the Public Service Commission of Maryland, on behalf of Baltimore Gas and Electric Co., etc.: Reply testimony on "code of conduct" issues. Filed October 26, 1999.

Before the Illinois Commerce Commission, on behalf of Illinois Power Company: Rebuttal testimony addressing the pricing of metering and billing services. Filed October 21, 1999.

Before the Maine Public Utility Commission, on behalf of CMP Group, Inc.: Rebuttal testimony on issues related to acquisition of CMP by Energy East. Filed October 13, 1999.

Before the Illinois Commerce Commission, on behalf of Illinois Power Company: Direct testimony addressing the proper pricing of metering and billing services. Filed October 8, 1999.

Before the Public Service Commission of Maryland, on behalf of Baltimore Gas and Electric Co., etc.: Direct testimony on "code of conduct" issues. Filed October 1, 1999.

Before the Maine Public Utilities Commission, on behalf of Central Maine Power Co.: Direct testimony addressing the proposed alternative ratemaking plan. Filed September 30, 1999.

Before the Michigan Public Service Commission, on behalf of Ameritech Michigan: Direct testimony regarding economic consequences resulting from full avoided cost discount as applied to resale of existing contracts. Filed September 27, 1999.

Before the Public Service Commission of West Virginia, on behalf of Allegheny Power and American Electric Power: Rebuttal testimony on "code of conduct" issues. Filed July 14, 1999.

Before the Maine Public Utilities Commission, on behalf of Central Maine Power Co.: Direct testimony on the acquisition of CMP by Energy East. Filed July 1, 1999.

Before the Public Service Commission of West Virginia, on behalf of Allegheny Power and American Electric Power: Direct testimony on "code of conduct" issues. Filed June 14, 1999.

Before the Illinois Commerce Commission, on behalf of Commonwealth Edison: Rebuttal testimony addressing the design of delivery services tariffs. Filed May 10, 1999.

Before the Subcommittee on Energy and Power, on behalf of National Economic Research Associates: Statement addressing electric restructuring market power issues. Filed May 6, 1999.

Before the New Jersey Public Utilities Board, on behalf of the Edison Electric Institute: Direct testimony on the PUC's draft affiliate relations standards. Filed May 3, 1999.

Before the US District Court, Western District of Pennsylvania, on behalf of Allegheny Energy, Inc.: Expert report on regulatory issues regarding the recovery of stranded costs, filed May 1989

Expert report, on behalf of ICG/Teleport addressing the way in which Denver's ordinance allocates costs among users of public rights-of-way. Filed April 21, 1999.

Before the Ohio Senate Ways and Means Committee, on behalf of the Ohio Electric Utility Institute: Direct testimony regarding restructuring of Ohio electricity industry. Filed April 20, 1999.

Before the Federal Energy Regulatory Commission, on behalf of the Central Vermont Public Service Corporation: Rebuttal testimony regarding CVPSC's reasonable expectation to serve its Connecticut Valley affiliate. Filed April 8, 1999.

Before the Joint Committee on Utilities and Energy, on behalf of the Central Maine Power Company: Direct testimony on rate design for recovery of stranded costs. Filed March 23, 1999.

Before the Illinois Commerce Commission, on behalf of the Commonwealth Edison Company: Direct testimony on Commonwealth Edison's delivery service tariffs. Filed March 1, 1999.

Before the Indiana Utility Regulatory Commission, on behalf of Ameritech Indiana: Direct testimony on interconnection issues between RBOC and independent LECs. Filed February 19, 1999.

Before the Indiana Utility Regulatory Commission, on behalf of Ameritech Indiana: Direct testimony on competitive flexibility and alternative rate plan issues. Filed January 29, 1999.

Before the Rhode Island Public Utilities Commission, on behalf of Bell Atlantic-Rhode Island: Rebuttal testimony regarding economic consequences of granting a request by CTC to assume BA-RI retail contract without customer penalty or termination charges. Filed December 4, 1998.

Before the Michigan Public Service Commission, on behalf of Ameritech Michigan: Surrebuttal testimony regarding interconnection agreement. Filed November 9, 1998.

Before the Michigan Public Service Commission, on behalf of Ameritech Michigan: Direct testimony regarding interconnection dispute with a CLEC. Filed October 20, 1998.

Before the Wisconsin Public Service Commission, on behalf of the Edison Electric Industry: Surrebuttal testimony on utility diversification issues. Filed October 16, 1998.

Before the Wisconsin Public Service Commission, on behalf of The Edison Electric Institute: Supplemental direct testimony addressing DSM issues and electric restructuring. Filed October 13, 1998.

Before the Virgin Islands Public Service Commission, on behalf of the Virgin Islands Telephone Company: Testimony regarding the Industrial Development Corporation tax benefit. Filed October 5, 1998.

Before the Wisconsin Public Service Commission, on behalf of The Edison Electric Institute: Rebuttal testimony addressing affiliate interest issues in a traditional regulatory environment. Filed October 2, 1998.

Before the Wisconsin Public Service Commission, on behalf of The Edison Electric Institute: Direct testimony addressing affiliate interest issues in a traditional regulatory environment. Filed September 9, 1998.

Before the Maine Public Utilities Commission, on behalf of Bell Atlantic-Maine: Declaration describing state regulation and special tariffs filed by Bell Atlantic. Filed August 31, 1998.

Before the Vermont Public Service Board, on behalf of Bell Atlantic-Vermont: Rebuttal testimony regarding economic consequences of granting CTC's request to allow assignment of BA-VT retail contracts without customer penalty or termination charges. Filed August 28, 1998.

Before the Massachusetts Department of Telecommunications and Energy, on behalf of Bell Atlantic-Massachusetts: Direct testimony commenting on economic consequences of CTC's policy of allowing customers to assign service agreements, without customer penalty, on resold basis to CTC. Filed August 17, 1998.

Before the Vermont Public Service Board, on behalf of Bell Atlantic-Vermont: Testimony regarding the economic consequences of granting a request by CTC to assume BA-VT retail contract without customer penalty or termination charges. Filed August 14, 1998.

Before the Illinois Commerce Commission, on behalf of Ameritech Illinois: Direct testimony on rate rebalancing plan. Filed August 11, 1998.

Before the Maine Federal District Court, on behalf of Bell Atlantic: Expert report responding to CTCs anti-competitive claims against Bell Atlantic-North. Filed July 20, 1998.

Before the New Hampshire Public Utilities Commission, on behalf of Bell Atlantic: Direct testimony on petition by CTC to assume contracts that CTC had won for Bell Atlantic when it was an agent. Filed July 10, 1998.

Before the Virgin Islands Public Service Commission, on behalf of VITELCO: Testimony on use of consultants by regulatory commissions; benefits of incentive regulation and treatment of tax benefits. Filed July 10, 1998.

Before the Public Utility Commission of California, on behalf of The Edison Electric Institute: Comments on the enforcement of affiliate transactions rules proposed by the California Public Utility Commission. Filed May 28, 1998.

Before the Public Service Commission of New Mexico, on behalf of Public Service Company of New Mexico: Rebuttal testimony regarding the Commission's investigation of the rates for electric service of PNM. Filed May 6, 1998.

Before the Oklahoma Corporation Commission, on behalf of Southwestern Bell Communications: Reply affidavit regarding SBC's application for provision of in-region interLATA service in Oklahoma. Filed April 21, 1998.

Before the Public Utility Commission of Texas, on behalf of Southwestern Bell Communications: Rebuttal testimony regarding SBC's application for provision of in-region interLATA service in Texas. Filed April 17, 1998.

Before the Public Service Commission of New Mexico, on behalf of the Public Service Company of New Mexico: Direct testimony to address the economic efficiency, equity, and public policy concerning PNM's company-wide stranded costs. Filed April 16, 1998.

Before the Illinois Commerce Commission (Docket nos. 98-00013 and 98-0035), on behalf of The Edison Electric Institute: Rebuttal testimony addressing the adoption of rules and standards governing relationships between energy utilities and their affiliates as retail competition in the generation and marketing of electricity is introduced, filed March 25, 1998. Surrebuttal filed March 11, 1998.

Before the Public Utility Commission of Texas, on behalf of Southwestern Bell Communications: Testimony regarding SBC's application for provision of in-region interLATA service in Texas. Filed February 24, 1998.

Before the Kansas Corporation Commission on behalf of Southwestern Bell Telephone Company: Direct testimony regarding SBC's application for provision of in-region interLATA service in Kansas. Filed February 15, 1998. Rebuttal filed May 27, 1998.

Before the Maine Public Utilities Commission, on behalf of Bell Atlantic - Maine: Testimony regarding the reasonableness of restructuring rates. Filed February 9, 1998.

Before the Arizona Corporation Commission, on behalf of Tucson Electric Power Company: Rebuttal testimony regarding the Commission's rules for introducing competition into the electric industry. Filed February 4, 1998.

Before the Oklahoma Corporation Commission, on behalf of Southwestern Bell Communications: Affidavit regarding SBC's application for provision of in-region interLATA service in Oklahoma. Filed January 15, 1998.

Before the Arizona Corporation Commission, on behalf of Tucson Electric Power Company: Testimony regarding the Commission's rules for introducing competition into the electric industry. Filed January 9, 1998.

Before the Maine Public Utilities Commission, on behalf of Central Maine Power Company: Testimony regarding the Commission's proposed affiliate rules. Filed January 2, 1998.

Before the Indiana Utility Regulatory Commission, on behalf of Ameritech Indiana: Testimony regarding Ameritech Indiana's proposal for an interim alternative regulation plan. Filed October 29, 1997.

Before the Public Utility Commission of Texas, on behalf of Entergy-Gulf States Utilities: Rebuttal testimony regarding Entergy's "Transition to Competition" proposal. Fled October 24, 1997.

Before the Illinois State Senate, "Report on SB 55," on behalf of Illinois Power Company: Report and Testimony on proposed electric industry restructuring legislation in Illinois. Filed October 9, 1997.

Before the Indiana Utility Regulatory Commission, on behalf of Ameritech Indiana: Testimony regarding Ameritech Indiana's proposal for a new alternative regulatory framework. Filed July 30, 1997.

Before the Public Utilities Commission of Ohio, on behalf of Ameritech Ohio: Testimony responding to AT&T's "Complaint against Ameritech Ohio, Relative to Alleged Unjust, Unreasonable, Discriminatory and Preferential Charges and Practices." Filed July 7, 1997.

Before the New Jersey Assembly Policy and Regulatory Oversight Committee, on behalf of Public Service Electric and Gas Company: Testimony regarding transition cost recovery from self generators. June 16, 1997.

Before the New Jersey Board of Public Utilities, on behalf of Public Service Electric and Gas Company: Testimony regarding transition cost recovery from self generators. Filed June 6, 1997.

Before the Federal Communications Commission: Reply Affidavit in support of SBC Communications Inc.'s application to offer interLATA service in Oklahoma. Filed May 27, 1997.

Before the Corporation Commission, on behalf of Kansas Pipeline Partnership: Testimony regarding Purchase Gas Adjustment proceeding for Western Resources, Inc. Filed May 7, 1997.

Before the Public Utility Commission of Texas, on behalf of Entergy-Gulf States Utilities: Supplemental direct testimony regarding Entergy's "Transition to Competition" Proposal. Filed April 4, 1997.

Before the Illinois Commerce Commission, on behalf of Ameritech Illinois: Testimony regarding price cap regulation. filed April 4, 1997

Affidavit: in support of SBC Communications Inc.'s application to offer interLATA service in Oklahoma. Before the Oklahoma Corporation Commission and the Federal Communications Commission. Filed February 20, 1997 (OCC) and April 7, 1997 (FCC).

Before the Federal Communications Commission, on behalf of Ameritech: Reply comments on access reform. Filed February 14, 1997.

Before the Federal Communications Commission, on behalf of Ameritech: Paper on access reform, “Access, Regulatory Policy, and Competition”, filed January 29, 1997.

Before the Wisconsin Public Service Commission, on behalf of Ameritech - Wisconsin: Testimony regarding interconnection arbitrations. Filed December 5, 1996.

Before the Public Utility Commission of Texas, on behalf of Entergy-Gulf States Utilities: Testimony regarding Entergy’s “Transition to Competition” proposal. Filed November 27, 1996.

Before the California Public Utilities Commission: Rebuttal testimony in support of the joint application of Pacific Telesis Group and SBC Communications Inc. for approval of their merger, (Application No. 96-04-038). November 8-9, 1996.

Affidavit: in support of Florida Public Service Commission’s appeal of Federal Communications Commission’s interconnection order (CC Docket No. 96-98). September 12, 1996.

Before the New Jersey Board of Public Utilities on behalf of Bell Atlantic - New Jersey: “Economic Competition in Local Exchange Markets,” position paper on the economics of local exchange competition filed in connection with arbitration proceedings, August 9, 1996 (with William E. Taylor and Alfred E. Kahn).

Federal Communications Commission (CC Docket No. 96-45) on behalf of BellSouth Corporation, “Comments on Universal Service,” (with William Taylor), analysis of proposed rules to implement the universal service requirements of the Telecommunications Act of 1996, filed April 12, 1996.

Before the Senate Committee on Commerce, Science and Transportation on FCC Structure and Function: Suggested Revisions, March 19, 1996.

Before the Federal Communications Commission in the Matter of Pricing for CMRS Interconnection on behalf of Ameritech, March 4, 1996.

Before the Senate Committee on Commerce, Science and Transportation on Telecommunications Reform on behalf of NARUC, March 2, 1995.

Before the House Committee on Energy and Commerce Committee, Subcommittee on Telecommunications and Finance on H.R. 4789, the Telephone Network Reliability Improvement Act of 1992, on behalf of NARUC, May 13, 1992.

Before the Senate Committee on Commerce, Science and Transportation on H.R. 2546, a bill proposing the Infrastructure Modernization Act of 1991, on behalf of NARUC., June 26, 1991.

SPEECHES (partial list)

Remarks before the 1996 Telecommunications Policy Research Conference, "Interconnection Principles and Efficient Competition", Solomon's Island, MD, October 7, 1996.

Remarks before the American Bar Association Section of Antitrust Law, "Charging Competitors and Customers for Stranded Costs: Competition Compatible?" Four Seasons Hotel, Chicago, IL, September 19, 1996.

Remarks before the 1996 EPRI Conference on Innovative Approaches to Electricity Pricing, "Prices and Profits: Perceptions of a Former Regulator," La Jolla, California, March 28, 1996.

Remarks before the Innovative Fuel Management Strategies for Electric Companies Conference sponsored by The Center for Business Intelligence, "Anticipating the Impact of Fuel Clause Reversal on Fuel Management," Vista Hotel, Washington, D.C., March 15, 1996.

Remarks before Electricity Futures Trading Conference, "Electricity Futures Trading: What the States Are Doing," Houston, Texas, March 14, 1996.

Panelist, "Regulatory Panel: Who Has Jurisdiction?" Public Power in a Restructured Industry, Washington, D.C., December 8, 1995.

Participant, "Public Policy for Mergers in a Time of Restructuring," Harvard Electric Policy Group, Crystal City, Virginia, December 7, 1995.

Panelist, Roundtable on "Competitive Markets in Electricity and the Problem of Stranded Assets," Progress and Freedom Foundation, Washington, D.C., December 1, 1995.

Panelist on "The Range of Uncertainty" at the Illinois Electricity Summit, Northwestern University, Evanston, IL., November 28, 1995.

PUBLICATIONS

"Demand Side Management in Today's Electricity Market," Electricity Deregulation Commentary, Maine Policy Review, Winter 2001, pp. 19-21.

"Reforming Universal Service One More Time," Communications Deregulation and FCC Reform: What Comes Next?, Jeffrey A. Eisenach and Randolph J. May, editors (Washington, D.C.: The Progress & Freedom Foundation, pp. 61-84. Conference Edition, December 2000.

"Back to the Basics: Federal Legislation, Electricity Deregulation," *The Boston Globe*, June 7, 2000.

"Consumer Sovereignty, Branding, and Standards of Competitive Practice," *Electricity Journal*, May 2000, Volume 13, Number 4, pp.76-84 (with Wayne Olson)

"Open Entry, Choice, and the Risks of Short-Circuiting the Competitive Process" prepared for the Edison Electric Institute, March 20, 2000. (with Wayne Olson)

"Getting it Right: Filling the Gaps in FERC's Stranded Cost Policies," *The Electricity Journal,* Volume 12, Number 4, May 1999.

"Choose the Right Recipe for Electric Deregulation," *The Star-Ledger,* December 16, 1998.

Prepared for Edison Electric Institute, "Fostering Efficient Competition in the Retail Electric Industry: How Can Regulators Help Solve Vertical Market Power Concerns? First, Do No Harm," July 22, 1998 (with Charles Augustine).

"The FCC's Common Carrier Bureau: An Agenda for Reform," Issue Analysis Number 62: Citizens for a Sound Economy Foundation, September 26, 1997 (with Paul Vasington).

"What Hath Hundt Wrought?," *Wall Street Journal*, page A18, May 30, 1997 (with Thomas J. Duesterberg).

Book: "Competition and Deregulation in Telecommunications: The Case for a New Paradigm," Hudson Institute, Indianapolis, IN, 1997 (with Thomas J. Duesterberg).

"The Regulators' and Consumer Advocate's Dilemma", *Purchased Power Conference*, Exnet, 1993.

"Public Utility Regulation: Reflections of a Sometime Deregulator", *Public Utilities Fortnightly,* Nov. 1, 1992.

"Utilities as Conservationists: One Regulator's Viewpoint', in *The Economics of Energy Conservation*, proceedings of a POWER Conference, Berkeley, CA, 1992.

"Incentive Regulation in Telecommunications: Lessons for Electric and Gas", in *Incentive Regulation*, Proceedings and Papers, 1992 (Exnet).

Public Utilities Fortnightly, State Regulators' Forum, Contributor since 1992.

"Competition, Deregulation and Technology: Challenges to Traditional Regulatory Process", *In Your Interest*, Minnesota Utility Investor, Inc., 1992.

"Policing the Environment", *Institutional Investor*, October, 1992.

"Regulation: Obstructer or Enabler?", in *Proceedings; Cooperation and Competition in Telecommunications*, Conference sponsored by the Commission of the European Directorate General XIII, Rome, 1993.

"A Basis for Allocating Regulatory Responsibilities", in Clinton J. Andrews, (ed.), *Regulating Regional Power Systems,* Quorum Books, Westport, CT, 1995 (with Christopher Mackie-Lewis).

Book review: Stephen Breyer, *Breaking the Vicious Circle: Toward Effective Risk Reduction*, Harvard University, Press, 1992, in Federal Reserve Bank of Boston, Regional Review, 1994.

"Weighing Environmental Coasts in Utility Regulation: The Task Ahead", *The Electricity Journal*, October, 1990.

"The Effects of Higher Telephone Prices on Universal Service" Federal Communications Commission, Office of Plans and policy, Working Paper No. 10, March, 1984 (with John Haring).

"Are Recent FCC Telephone Rate Reforms a Threat to Universal Service" in Harry S. Trebing (ed.), *Changing Patterns in Regulation, Markets and Technology: The Effect on Public Utility Pricing*, University of Michigan Press, 1984 (with John Haring).

"A Framework for a Decentralized Radio Service, "a staff report of the Office of Plans and Policy, Federal Communications Commission. September, 1983 (with Alex Felker).

"L'impact de la television par cable sur les autres medias" (The Impact of Cable Television on other media in the United State"), *Trimedia*, numero 18019, printemps, 1983 (in French, also reprinted in Spanish).

"FCC Policy on Cable Ownership" in Gandy, Espinosa & Ordover, (eds.) *Proceedings from the Tenth Annual Telecommunications Policy Research Conferences,* ABLEX, Norward, N.Y., 1983.

"FCC Policy on Cable Crossownership", a staff report of the Office of Plans and Policy, Federal Communications Commission, November, 1981. (With Jonathan levy and Robert S. Preece; I was director of the study.)

"Economics and Telecommunications Privacy: A Framework for Analysis," Federal Communications Commission, Office of Plans and Policy, Working Paper No. 5, December, 1980. (With James A. Brown).

"The Effects of Minimum Wage on Private Household Workers" in Simon Rottenberg, (ed.), *The Economies of Legal Minimum Wages*, American Enterprise Institute, Washington, 1981.

"Deregulation, Rights and the Compensation of Losers, "in William G. Shepherd and Kenneth Boyer, eds., *Economic Regulation: A Volume in Honor of James R. Nelson*, University of Michigan Press, 1981. Also circulated as American Enterprise Institute Working Paper in Regulation, 1980.

"Social Security and Welfare: Dynamic Stagnation", *Public Administration Review*, March 1967.

INCIDENTAL TEACHING AND LECTURING

University and College
Yale School of Management and Organization
Harvard Law School, Telecommunications Seminar
Suffolk University Law School
University of Maine
Boston University

Other
Edison Electric Institute
(Electricity Consumers Resource Council)

June 18, 2003

EXHIBIT
APS-13
Admitted

PINNACLE WEST ENERGY

Warren C. Kotzmann
Vice President,
Financial & Corporate Services

400 N. 5th Street
Mail Station: 8983
Phoenix, AZ 85004

Office: (602) 250-3861
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Warren.Kotzmann@pwenergy.com

November 9, 2004

Steve Wheeler
Arizona Public Service Company
MS: 9040
P.O. Box 53999
Phoenix, AZ 85072-3999

Dear Mr. Wheeler,

This letter confirms that Pinnacle West Energy Company ("PWEC") has read and understands the proposed settlement agreement between APS and various intervening parties, dated August 18, 2004 ("Settlement Agreement"). This letter further confirms that PWEC will abide by those provisions of the Settlement Agreement that require PWEC to take any action or to refrain from taking action in order to carry out the intent of the Settlement Agreement.

Sincerely

Warren C. Kotzmann

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EXHIBIT ______
(Robinson)

PWEC Unit Native Load and Off-System Sales

Time Period	APS Native Load Usage	Percent Sold Off-System [1]
June 2002 - December 2002	78%	22%
January 2003 - December 2003	70%	30%
January 2004 - September 2004	79%	21%

/1/ Off-system sales are all sales made to third parties when not used for Native Load. It is impossible to determine the ultimate destination of that energy.

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EXHIBIT ____
(Robinson)

General Practice by State
of Fuel and Purchased Power Cost Recovery

State	Cost Pass-Through
AL	X
AR	X
CA	X
CO	X
CT	X
DE	X
DC	
FL	X
GA	X
HI	X
ID	X
IL	X
IN	X
IA	X
KS	X
KY	X
LA	X
ME	X
MD	X
MA	X
MI	X
MN	X
MS	X
MO	

State	Cost Pass-Through
MT	
NV	X
NH	X
NJ	X
NM	X
NY	X
NC	X
ND	X
OH	
OK	X
OR	X
PA	
RI	X
SC	X
SD	X
TN	X
TX	X
UT	
VT	
VA	X
WA	X
WV	X
WI	X
WY	X

Source: Special Report; Fuel and Wholesale Power Recovery
Regulatory Research Associates; dated July 26, 2004

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EXHIBIT ___
(Robinson)

APS Rate Case Settlement
Docket No. E-01345A-03-0437
ACC Action Items Listing

			Implementation or Action Required By		
Component of Rate Settlement (with References)		**Requirement**	APS	Staff	Commission
PWEC ASSET ISSUES **Section II**					
	Paragraph 9	File with FERC within 30 days of Commission approval of Rate Settlement ("Agreement") if needed.	X		
	Paragraph 10 Paragraph 11	APS and PWEC will execute Bridge PPA from effective date of rate increase and actual date of asset transfer. If FERC denies transfer, Bridge PPA converts to a 30-year PPA.	X		
	Paragraph 13	If FERC issues an order approving APS' request to acquire the PWEC Assets at a value materially less than $700 million, APS will promptly file an appropriate application.	X	X	X
	Paragraph 69 & 71	APS will issue an RFP in 2005 for 100 MW of renewable resources.	X		
COMPETITIVE PROCUREMENT OF POWER **Section IX**					
	Paragraph 74	APS is precluded from self-building prior to Jan. 1, 2015 unless specifically approved by Commission.	X	X	X
	Paragraph 78	APS will issue an RFP or other competitive solicitation(s) no later than the end of 2005 seeking long-term future resources of not less than 1,000 MW for 2007 and beyond.	X		
COMPLIANCE FILINGS					
	POWER SUPPLY ADJUSTOR ("PSA") **Section IV**				
	Paragraph 19 b	APS will file a report showing calculation of new rate March 1, 2006 and thereafter on March 1st of each subsequent year for an April 1 effective date.	X	X	
	Paragraph 19 e	If the Balancing Account reaches + or - $50 million, APS will file within 45 days.	X	X	X
	Paragraph 20	Within 60 days of effective date of Commission order approving Agreement, APS will provide monthly reports detailing all calculations related to the PSA.	X		
	Paragraph 21	Within 60 days of effective date of Commission order approving Agreement, APS will provide monthly reports about APS' generating units, power purchases and fuel purchases. Due on 1st day of the 3rd month following end of reporting month.	X		

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EXHIBIT ___
(Robinson)

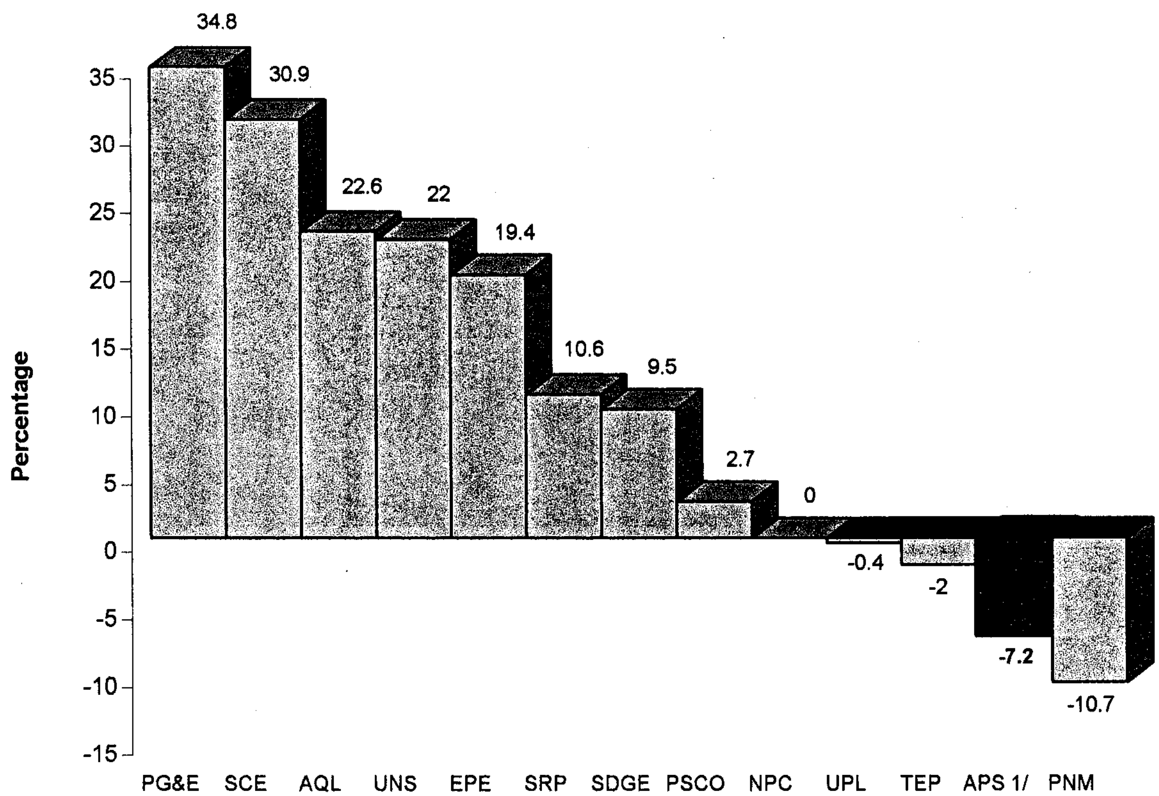
Component of Rate Settlement (with References)	Requirement	Implementation or Action Required By: APS	Staff	Commission
Paragraph 25	Within 60 days of effective date of Commission order approving Agreement, APS will provide a report relating to the base cost of fuel and purchased power adopted for the test year settlement revenue requirement.	X		
Paragraph 28	No later than 4 years from date of PSA, APS will file report regarding PSA operation, merits, shortcomings and recommendations.	X		
DEMAND SIDE MANAGEMENT ("DSM") Section VII				
Paragraph 41	APS must submit any new DSM programs for pre-approval before APS may include costs in any determination of total DSM costs incurred (Preliminary Plan provided as Appendix B to Agreement).	X	X	X
Paragraph 43	APS will file a report showing calculation of new rate March 1, 2006 and thereafter on March 1st of each subsequent year for an April 1 effective date.	X	X	
Paragraph 48	Within 120 days of Commission approval of preliminary plan, APS will file a final 2005 DSM plan.	X	X	X
Paragraph 52	APS will file mid-year and end-year reports. Each report will be due on the first day of the third month after the conclusion of the reporting period.	X		
Paragraph 54	APS will implement and maintain a collaborative DSM working group (including Staff, RUCO, AECC, AZ State Energy Office, WRA and SWEEP).	X		
ENVIRONMENTAL PORTFOLIO STANDARD AND OTHER RENEWABLE PROGRAMS ("EPS") Section VIII				
Paragraph 63	APS may file for an adjustment to the current EPS surcharge to allow for additional EPS funding.	X	X	X
Paragraph 67	APS must submit any new EPS programs directly involving retail customers for approval.	X	X	X
PLANS FOR ADMINISTRATION				
Paragraph 32 Paragraph 60 Paragraph 89 Paragraph 96 Paragraph 107	Within 60 days of effective date of Commission order approving Agreement, APS will file Plans of Administration for: ▪ PSA ▪ DSM ▪ CRCC ▪ RCDAC ▪ TCA	X	X	

EXHIBIT ____
(Robinson)

Component of Rate Settlement (with References)		Requirement	Implementation or Action Required By		
			APS	Staff	Commission
	SERVICE SCHEDULES/TARIFFS				
	Paragraph 135	Within 60 days of effective date of Commission order approving Agreement, APS will file compliance tariffs.	X	X	
	STUDIES				
	Paragraph 55	Within one year of effective date of Commission order approving Agreement, APS will file study to review and evaluate merits of allowing large customers to self-direct any DSM investments.	X		
	Paragraph 57	APS will conduct a study analyzing rate design modifications that could include, among others, consideration of mandatory TOU rates. (e.g., for E-32 GS customers) and/or expanded use of inclining block rates. A plan for such study shall be presented to the collaborative DSM working group within 90 days of the Commission's approval of Settlement Agreement. APS will submit final results to Commission within 15 months of approval of Settlement Agreement or as part of next general rate case (whichever comes first) .	X		
	Paragraph 116	Within 180 days of this Agreement, APS will submit study examining ways to provide a more flexible TOU rate design (ET-1 and ECT-1R).	X		
	Paragraph 117	APS will provide monthly reports evaluating the outcome of above study – due within 12 months from date of decision in this matter.	X		
	Working Groups				
	Paragraph 79	Commission Staff will schedule workshops on resource planning issues – no specific date set.		X	
	Paragraph 108	Commission Staff will schedule workshops to consider outstanding issues affecting distributed generation.		X	
	Initiation of Rulemakings				
	Paragraph 68	Within 120 days of approval of Agreement, Staff will initiate a rulemaking proceeding to modify Rule 1618.		X	

EXHIBIT _____
(Robinson)

Cumulative Rate Changes 1999-2004
Western Utilities



Utilities are: Pacific Gas and Electric, Southern California Edison, Aquila Networks - WPL (Colorado), Unisource, El Paso Electric - New Mexico, Salt River Project, San Diego Gas and Electric, Public Service of Colorado, Nevada Power Company, Utah Power and Light, Tucson Electric Company, Arizona Public Service Company, and Public Service of New Mexico.

1/ APS rates have decreased a total of 15.5% since 1992.

Source: *Regulatory Research Associates*

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MARC SPITZER, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
MIKE GLEASON

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACTS	DOCKET NO. E-01345A-03-0437

ARIZONA PUBLIC SERVICE COMPANY'S

NOTICE OF FILING REQUESTED INFORMATION

Arizona Public Service Company ("APS") hereby files certain information requested by one or more of the Commissioners during the initial days of hearing in the above-referenced docket. Attached is a chart that APS will have marked as an exhibit at the hearing.

EXHIBIT
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APS-18
Admitted

RESPECTFULLY SUBMITTED this 29 day of November, 2004.

PINNACLE WEST CAPITAL
CORPORATION LAW DEPARTMENT

By: Karilee S. Ramaley
Thomas L. Mumaw
Karilee S. Ramaley
Attorneys for Arizona Public
Service Company

The original and 10 copies of the foregoing were
filed this 29th day of November, 2004 with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007.

Copies of the foregoing mailed, faxed or
transmitted electronically this
29th day of November, 2004 to:

All parties of record.

Vicki DiCola
Vicki DiCola

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MARC SPITZER, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
MIKE GLEASON

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACTS	DOCKET NO. E-01345A-03-0437

ARIZONA PUBLIC SERVICE COMPANY'S

NOTICE OF FILING REQUESTED INFORMATION

Arizona Public Service Company ("APS") hereby files Exhibit APS_18 Revised, which responds to a request by one or more of the Commissioners during the initial days of hearing in the above-referenced docket. APS will have the attached exhibit marked at the hearing.

12/1/04 EXHIBIT
APS 18
Revised
Admitted

RESPECTFULLY SUBMITTED this 1st day of December, 2004.

PINNACLE WEST CAPITAL
CORPORATION LAW DEPARTMENT

By: Karilee S. Ramaley
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Service Company

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Vicki DiCola
Vicki DiCola

REVISED EXHIBIT 18
(Robinson)

Arizona Public Service Company
Commissioner Mayes' E-12 Request
E-12 Customers' Average & Median Monthly Bill with Increase and Adjustors

	Settlement Rates E-12 Average Usage [1]	Settlement Rates E-12 Median Usage [1]	APS Direct Case Rates E-12 Average Usage [1]
Customer kWh	738	460	738
Monthly Base Bill at Current Rates excluding Franchise Fee[2]	$ 70.72	$ 42.55	$ 70.72
Plus EPS Charge at Current Rate	$ 0.35	$ 0.35	$ 0.35
Plus Franchise Fee at 1.44%[3]	$ 1.02	$ 0.62	$ 1.02
Monthly Base Bill at Current Rates	$ 72.09	$ 43.52	$ 72.09
Monthly Base Bill at Settlement Rates	$ 73.55	$ 44.20	$ 76.09
Plus EPS Charge at Current Rate	$ 0.35	$ 0.35	$ 0.35
Plus CRCC	$ 0.25	$ 0.16	$ 0.26
Plus Franchise Fee at 1.44%	$ 1.07	$ 0.64	$ 1.10
2005 Monthly Bill at Settlement Rates	$ 75.22	$ 45.35	$ 77.80
Percent Increase from Current Rates	4.34%	4.21%	7.92%
Potential 2006 Adjustments			
Plus PSA 4 Mill [4]	$ 2.95	$ 1.84	$ 2.95
Plus TCA (5% Trigger)[5]	$ 0.18	$ 0.11	$ 0.18
Plus Residential EPS [6]	$ -	$ -	$ -
Plus DSM $6 Million [7]	$ 0.15	$ 0.10	$ -
Plus Franchise Fee on Potential Adjustments at 1.44%	$ 0.05	$ 0.03	$ 0.05
2006 Monthly Bill at Settlement Rates with Adjustors[8]	$ 78.55	$ 47.43	$ 80.98
Overall Increase from Current Rates	$ 6.46	$ 3.91	$ 8.89
Overall Percent Increase from Current Rates	8.96%	8.98%	12.33%

[1] Based on June 2004 usage data.
[2] Bill is calculated using APS' 7/1/03 rates. Taxes and Reg. Assessment are not included.
[3] The Average Test Year Franchise Fee of 1.44% from the Test Year was used for this calculation. The fee will vary among the cities.
[4] Actual impact in 2006 will vary depending on factors such as gas and coal prices, transportation costs, customer growth, customer usage, fuel mix, off-system sales, and other factors.
[5] A 5% increase in the current transmission rate would be necessary for this increase to occur.
[6] No change unless authorized by the ACC in a subsequent proceeding.
[7] Assumes ACC approval of DSM programs @ $16 Million per year. APS Direct Case Rates did not have a DSM Adjustor.
[8] The Adjustments shown will not be effective before April 2006.

APS Exhibit No. __________

ISSUES STILL IN CONTENTION
NOT SPECIFICALLY ADDRESSED IN STAFF SETTLEMENT TESTIMONY

Issue	Estimated Unresolved Differences ($M)
Lead-Lag Study	$ 10.3
Deferred PacifiCorp Gain	1.2
Regulatory Asset Amortization	2.5
Property Taxes	9.2
Economic Development Expenses	1.9
Advertising Expenses	4.4
Amortization of Severance Costs	6.2
Incentive Compensation	2.9
Customer Annualization	0.4
Total Unresolved Issues	$ 38.9

The values shown above are APS' estimates of the remaining value of unresolved issues. Since the above issues included not only whether these adjustments were appropriate but also their calculation, the total shown will not agree exactly with that shown by Staff or RUCO.

Admitted

EXHIBIT

tabbies

APS 19

LB 12/2/09

Q3-7 IN REFERENCE TO THE PROPOSED SETTLEMENT IN THI RATE PROCEEDING

EXHIBIT
APS-20
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a) Identify each paragraph to which AzCA objects.
b) The basis for such objection.
c) All information, data, etc., within the possession of AzCA or any of its members that supports the claimed basis for such objection,

A3-7 Answers:
a). AzCA objects to Section XVII. Distributed Generation, paragraphs 108 and 109, because we do not believe that ACC Staff workshops alone will foster a fair hearing without Commissioner Endorsement.

A Distributed Generation and interconnection Investigation, Docket E-00000A-99-0431 was held by the Arizona Corporation Commission from July 1999 through February 2000. One hundred and twenty three people participated and no action resulted from the investigation. APS unilaterally issued its own interconnection standards and no APS DG tariffs were ever affected.

What we do wanted as part of a Settlement is as follows:
1, Interconnection standards that are fair and include features from IEEE #1547 and NARUC guidelines.
2. Rate structures that do not discourage, but instead are fair to DG.

We object to all paragraphs that include references to Rate Design for General Service customers, particularly rates E-32, & E-32R.

We object to with Paragraph 122 on page 23 that eliminates most of the Companies General Service TOU rates, (E-21, E-22, E-23, and E-24)

We do agree with Paragraph 57 on Page 12. But, we believe it should not be left to the company to analyze what rates are “reasonable, cost-effective, and Practical”.

b) The basis for our objection is that these areas will have the effect of discouraging Distributed Generation (DG)
This is covered more fully in Mr. Murphy’s original testimony and the comments he gave during the Settlement negotiations.

c) This request is considered overly broad and intrusive and not designed to lead to the discovery of relevant evidence. Additionally we do not know what information our members possess. As to Mr. Murphy’s information, his data and information will be presented in his testimony.

EXHIBIT
APS-21
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AGREEMENT ON THE POWER SUPPLY ADJUSTOR TREATMENT OF SYSTEM BOOK OFF-SYSTEM SALES REVENUE

The affected parties to the proposed settlement agree that the treatment of the System Book Off-System Sales Revenue included in the Power Supply Adjustor described in Section IV of the August 18, 2004 Settlement Agreement filed in Arizona Corporation Commission Docket No. E-01345A-03-0437 will be as described and shown on following pages of this exhibit.

Dated this 3rd day of December, 2004.

ARIZONA CORPORATION COMMISSION STAFF

By Christopher Kempley

ARIZONANS FOR ELECTRIC CHOICE & COMPETITION

By Kevin C. Higgins

ARIZONA PUBLIC SERVICE COMPANY

By ____________________

RESIDENTIAL UTILITY CONSUMER OFFICE

By Scott Wakefield

Description of the Power Supply Adjustor's Treatment of System Book Off-System Sales Revenue

The Power Supply Adjustor includes the off-system sales revenue in the calculation of the Net Power Supply Cost. The monthly Net Power Supply Cost is the monthly Total System Book Fuel and Purchased Power Costs less the System Book Off-System Sales Revenue. The Off-System Sales Revenue includes the off-system sales using APS owned, or contracted, generation and purchased power related to optimizing the APS system. An example of this calculation is shown below.

ARIZONA PUBLIC SERVICE COMPANY
Example PSA Calculation Methodology to Illustrate Treatment of Off-System Sales

Line No.	Month	(a) Retail Energy Sales (kWh)	(b) Native Load Wholesale Energy Sales (kWh)	(c) Total Native Load Energy Sales (kWh)	(d) Total System Book Fuel and Purchased Power Costs	(e) System Book Off-System Sales Revenue	(f) Total Net Power Supply Cost
				(a +b)			(d - e)
1	January	1,963,130,000	14,210,000	1,977,340,000	$ 47,969,280	$ 19,289,000	$ 28,680,280
2	February	1,801,819,000	16,451,000	1,818,270,000	$ 40,807,680	$ 15,833,000	$ 24,974,680
3	March	1,712,984,000	14,840,000	1,727,824,000	$ 38,738,880	$ 13,319,000	$ 25,419,880
4	April	1,665,949,000	30,025,000	1,695,974,000	$ 43,948,800	$ 7,099,000	$ 36,849,800
5	May	1,844,862,000	41,471,000	1,886,333,000	$ 53,191,680	$ 13,202,000	$ 39,989,680
6	June	2,216,556,000	33,074,000	2,249,630,000	$ 63,962,880	$ 11,605,000	$ 52,357,880
7	July	2,615,184,000	40,929,000	2,656,113,000	$ 72,621,120	$ 7,295,000	$ 65,326,120
8	August	2,699,139,000	50,723,000	2,749,862,000	$ 73,295,040	$ 5,674,000	$ 67,621,040
9	September	2,575,503,000	48,814,000	2,624,317,000	$ 58,077,120	$ 5,336,000	$ 52,741,120
10	October	2,154,054,000	28,146,000	2,182,200,000	$ 53,153,280	$ 20,219,000	$ 32,934,280
11	November	1,768,036,000	21,562,000	1,789,598,000	$ 40,514,880	$ 21,537,000	$ 18,977,880
12	December	1,834,804,000	16,022,000	1,850,826,000	$ 51,711,360	$ 24,054,000	$ 27,657,360
13	Total	24,852,020,000	356,267,000	25,208,287,000	$ 637,992,000	$ 164,462,000	$ 473,530,000

EXHIBIT
APS-22
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American Jobs Creation Act of 2004 - Domestic Production Deduction

The American Jobs Creation Act of 2004 added new Internal Revenue Code Section 199 which provides a deduction equal to a percentage of the income earned from manufacturing undertaken in the United States. The deduction is the lesser of *either*:

1. The lesser of qualified production activities income or consolidated taxable income;
   or
2. 50% of the consolidated wages.

Qualified production activities income is derived as follows:

Qualified Production Activities Gross Receipts (QPAGR)
Less: Cost of goods sold related to such receipts
Less: Other directly allocable deductions, expenses or losses
Less: Ratable portion of indirect deductions, expenses or losses
Equals: Qualified Production Activities Income (QPAI)

QPAI essentially approximates the "taxable income" of generation activities. The maximum deduction is 3% of QPAI for 2005 and 2006, 6% for 2007-2009 and 9% for 2010 and thereafter.

QPAGR includes gross receipts of a taxpayer that are derived from "any sale, exchange or other disposition of electricity produced by the taxpayer in the United States." QPAGR does not include gross receipts related to transmission or distribution of electricity.

The specific manner in which QPAI is to be calculated is unclear. Treasury has indicated that they will promulgate as soon as practicable regulations which will provide guidance as to how to calculate QPAI.

Application to APS

The domestic production deduction will apply to APS' generation activities only. Until regulations are issued, the amount of this deduction cannot be determined. However, APS has roughly estimated this impact on federal tax expense for 2005 to be approximately $1 to $2 million. This benefit amount was derived by multiplying APS' pretax book income by the ratio of net generation plant to total APS net plant (with net generation plant and APS net plant as rate base proxies), which is based on the method being proposed to the IRS by EEI.[1]

We do not anticipate that the limitation of the deduction to 50% of consolidated wages will impact the APS deduction. Thus, the relative labor intensity of fossil/nuclear generation versus renewable generation is not a factor in determining the deduction for APS.

In addition to the domestic production deduction, the American Jobs Creation Act of 2004 extended renewable electricity production credits through 2005 and included an expansion of the renewable resources eligible for those credits (most notably to include solar energy). However, there were no generator fossil fuel incentives, such as clean coal technology credits, included in the American Jobs Creation Act of 2004.[2]

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[1] Final Regulations may dictate another approach for deriving QPAI from generation activities.
[2] The Act did create an alternative credit for the production of refined coal. This credit is only available to the operators of qualifying refined coal production facilities placed in service after the date of enactment, not to the purchaser of the coal (i.e., electric utilities).

EXHIBIT
APS-23
Admitted

Undergrounding Distribution and Sub-Transmission Lines

APS presently has approximately 25,000 miles of distribution facilities (12KV and 21KV) of which 52% are underground. APS also has 2,300 miles of sub-transmission facilities (69KV), with less than 1% underground. The company typically adds about 700 miles of distribution lines and 20 miles of sub-transmission lines each year.

Historically and currently, undergrounding costs have been paid by the benefiting party. Approximately 80% of all new distribution is installed underground because developers and homebuilders request underground service to meet market demand and to comply with legal requirements.

Estimated Average Costs for New Construction and Conversions

I. New Construction
Distribution - $460,000/mile for underground, $120,000/mile for overhead
Sub-transmission - $1,000,000/mile for underground, $185,000/mile for overhead

Total annual cost of underground new construction
Distribution $340,000 x 700 miles = $238,000,000
Sub-Transmission $815,000 x 20 miles = $16,300,000
Total Additional New Construction Cost = **$254 million per year** (without inflation)

II. Conversion of overhead to underground
Conversion from overhead to underground is significantly more expensive due to the additional expense incurred to remove the existing facilities and may have unrecovered costs for such existing facilities.

Approximate cost for conversion of distribution = $520,000/mile
Existing overhead facilities is approximately 12,000 miles
Total cost for distribution is $6.24 billion

Approximate cost for conversion of sub-transmission = $1,120,000/mile
Existing overhead facilities is approximately 2,300 miles
Total cost for sub-transmission is $2.58 billion

Total Conversion Cost = $8.82 billion
Assuming a 15 year period for conversion - **$588 million per year** (without inflation)

III. Summary
Total cost new construction and conversion = **$842 million per year** (without inflation)

Annual revenue requirement associated with these costs is approximately $110 million, which equates to an approximate **6% rate increase per year.**

Additional Issues for Consideration

- Customers currently served by underground facilities have already paid the incremental cost of placing the facilities underground but would be required to bear the cost for undergrounding lines that only benefit other customers if the costs were included in rates.

- Undergrounding APS distribution and sub-transmission lines would not eliminate the need for poles because other utilities use the same poles (e.g., telephone, cable). Separate arrangements would need to be made with other users of such joint-use facilities to completely remove the poles.

- Individual customers who are currently served with overhead facilities would incur additional costs to modify their meter panel to accept underground service and such modification may require those customers to bring portions of their electrical system up to current electrical codes.

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WREGIS Overview
The Western Renewable Energy Generation Information System (WREGIS) is a voluntary renewable energy tracking system being developed for the California Energy Commission (CEC) and the Western Governor's Association (WGA) with stakeholder input. California utilities are required by law to report their progress towards meeting the California RPS and the CEC has envisioned WREGIS as this tracking system. Other western utilities may participate voluntarily. WREGIS will track and certify renewable energy generation in the west. WREGIS will be housed at the Western Electricity Coordinating Council (WECC) as a board committee.

WREGIS is only an accounting system, not a trading platform. The California utilities and others that wish to voluntarily report and track their renewable energy generation may use this accounting system to confirm their renewable energy generation and ownership only. WREGIS is not a trading system for renewable energy, green tags or RECs (renewable energy credits).

Current status of WREGIS
A consultant hired by the CEC and the WGA have developed operational and financial proposals with input from stakeholders and submitted those proposals to the CEC and WGA. The CEC has the lead in finalizing the structure of the organization and working out the details with WECC since the CEC is the primary funding source for WREGIS. Once the mechanics have been worked out, a consultant will be hired by the CEC to construct the database system. WREGIS should be operational in 2006.

PINNACLE WEST
CAPITAL CORPORATION

Edward Z. Fox
Vice President
Communications,
Environment and Safety

February 18, 2004

William Mundell
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

SUBJECT: Western Renewable Energy Information System (WREGIS)

Dear Commissioner Mundell:

In response to your request to Mr. Wheeler we would like to offer the following comments on the establishment of the Western Renewable Energy Information System (WREGIS).

APS supports the initiative to create a regional system to track renewable energy credits and the ACC staff's participation in its development. It is important; however, that the staff remains true to certain principles that will protect Arizona's goals and objectives to develop the State's renewable energy sources.

We believe any system must be transparent, market driven and non-bureaucratic. The system must be limited to tracking renewable generation and should not try to create a trading system (eg: the Chicago Exchange), which is best left to the private sector.

Staff can play an instrumental role to protect Arizona's interests as established in the Environmental Portfolio Standard (EPS). Staff's work should ensure that any regional definition of Renewable Energy Credits conform to Arizona's EPS and that dollars dedicated to environmental benefits in Arizona are not redirected to other purposes.

In addition, we request that staff be directed to report on its activities and positions on WREGIS in the open staff meetings and bring any proposed outcome of the process to Arizona stakeholders for review and comment prior to any action by the ACC.

P.O. Box 53999 Station 9085 Phoenix, AZ 85072-3999 602-250-2916 Fax 602-250-3002 E-Mail: edward.fox@pinnaclewest.com

The outcome of this process can significantly shape – either positively or negatively – the development of renewable resources in Arizona. We hope that the Commission and Staff will take steps in this process to make certain that Arizona's renewable energy goals are realized to the benefit of all Arizona.

Sincerely,

Edward Z. Fox

Net Lost Revenue/Financial Incentives for DSM programs

APS examined 20 states with DSM programs that are implemented by utilities or independent program administrators serving the same function as the utilities. These 20 states represent a significant majority (over 70%) of all DSM spending nationally. Of these states, 17 of 20 provide net lost revenue recovery, financial incentives for program performance, a rate of return on DSM investments, or a combination of these. A summary table is attached which provides a state-by-state analysis of DSM incentives.

DSM Incentives for Utilities – Table of State Policies

	Net lost revenue recovery	Rate of return allowed on DSM costs	Financial incentives	Comments
Arizona	x		x	Both net lost revenue and financial incentives were historically allowed (see attached); APS has not sought incentives or revenue recovery for current market transformation programs.
California	Provided prior to 2002.			Changed policy concurrent with energy crisis, PUC is currently examining need to reinstate some form of financial incentives or revenue recovery.
Colorado		x		
Connecticut			x	Annual incentive based on percent of program expenditures contingent on meeting program goals.
Florida	x	x	x	Allow capitalization of some program costs. Allow "case by case consideration of lost revenue recovery and incentives"
Hawaii	x	x		
Indiana	x			
Kansas	x			
Massachusetts			x	Annual incentive based on percent of program expenditures contingent on meeting program goals.
Minnesota			x	Annual incentive based on percent of program expenditures contingent on meeting program goals.
Montana	PUC is currently considering	x		NW Utility currently has requested recovery of net lost revenues as they are ramping up DSM program.
Nevada		x	x	
New Jersey	x			Currently moving toward PUC run programs rather than utility run programs.
North Carolina	x			
Oregon	x	x	x	Most programs administered by non-profit Oregon Trust. Incentives available for "legacy programs" during transition to trust administration. Some utilities outside trust still retain right to collect lost revenues.
South Carolina	x			

Texas				
Vermont			x	Programs implemented by an independent program administrator who receives incentives based on program performance.
Washington				
Wisconsin			x	Programs implemented by an independent program administrator who receives incentives based on program performance.

Oregon "Conservation Tariff" Concept – Article Highlights (Referred to by Chairman Spitzer)

- Traditional utility ratemaking pits interests of consumers and shareholders against each other in energy efficiency/DSM efforts.
- By relying on volumetric rates to cover fixed costs, shareholders have a vested interest in customers using more energy.
- More kWh sales = greater cost recovery; reduced sales = less ability to recover fixed costs
- Under the traditional structure, a utility can only meet its financial obligations if it meets or exceeds projected sales volumes.
- Northwest Natural Gas in Oregon made a compact with customer's and commission called a "conservation tariff". The basic concept – don't penalize us for DSM efforts and we will do everything we can to encourage conservation.
- How does it work? Uses modest, regular true-up in rates to ensure that any fixed costs recovered are not "held hostage" to sales volume (i.e. eliminates net lost revenue issue).
- They use a process to establish baseline usage for customers. Actual usage in a given year is then normalized for weather and price elasticity and any change beyond that is identified as conservation.
- This concept was recommended by EEI and the Natural Resources Defense Council to NARUC in November 2003.
- The Oregon Conservation Tariff was approved by the Oregon Commission in October 2002 with support from the Citizens Utility Board and the NW Energy Coalition.

Source: Gary Clouser, EnergyPulse.net, 10.20.04; based on presentation by Mark Dodson (CEO, Northwest Natural Gas) at Bonneville Power Administration "Energizing the Northwest" conference in September 2004.

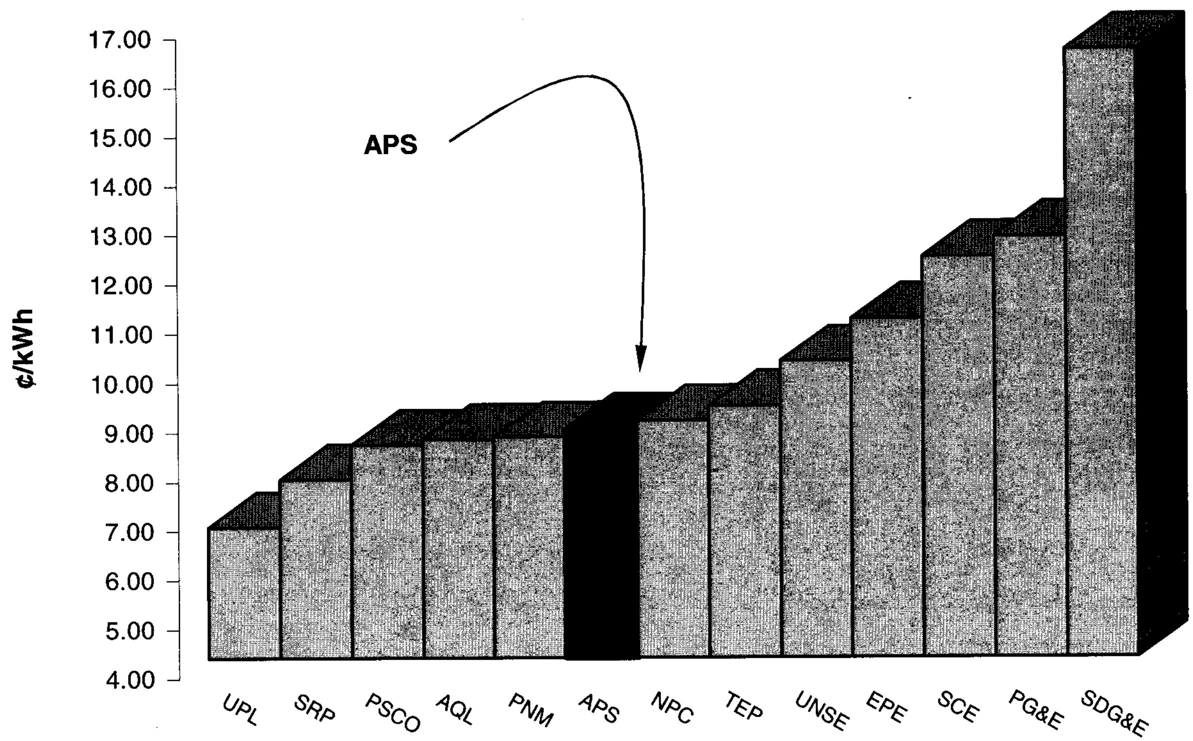
DSM Expenditures 1992-1999*		% of Total
Program Costs	$28,380,457	74%
Net Lost Revenue	$7,171,195	19%
Financial Incentives	$2,806,085	7%
Total	$38,357,737	100%

* DSM program scope and funding was significantly reduced by the ACC in 1999. ACC has previously ordered recovery of net lost revenues and financial incentives. The amounts above are reflective of these Orders.

APS EXHIBIT ______

EXHIBIT
APS-26
Hamilton

Average Residential Prices
Western Utilities
Year Ending 12/31/2003

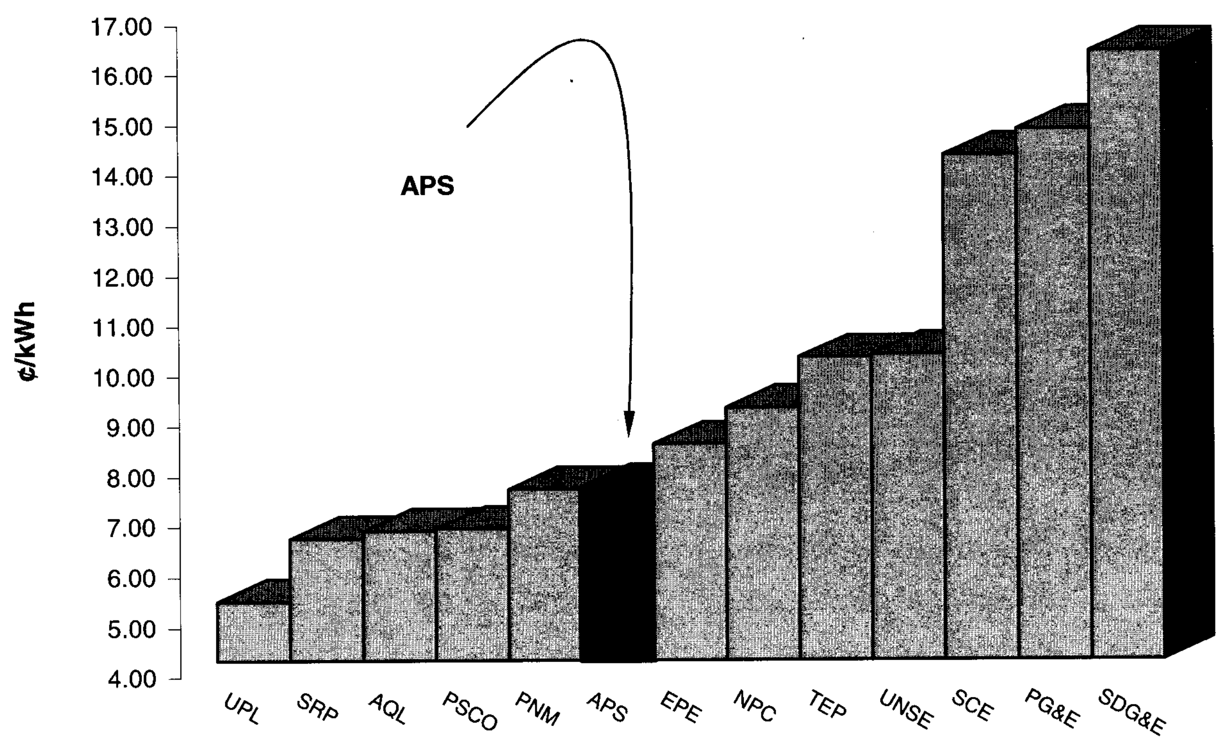


Utilities are: Utah Power and Light, Salt River Project, Public Service of Colorado, Aquila Networks - WPE (Colorado), Public Service of New Mexico, Arizona Public Service, Nevada Power Company, Tucson Electric Power, Unisource Electric, El Paso Electric - New Mexico, Southern California Edison, Pacific Gas and Electric, and San Diego Gas and Electric.

Source: Energy Velocity Database for 2003

APS EXHIBIT ____

Average Commercial Prices
Western Utilities
Year Ending 12/31/2003

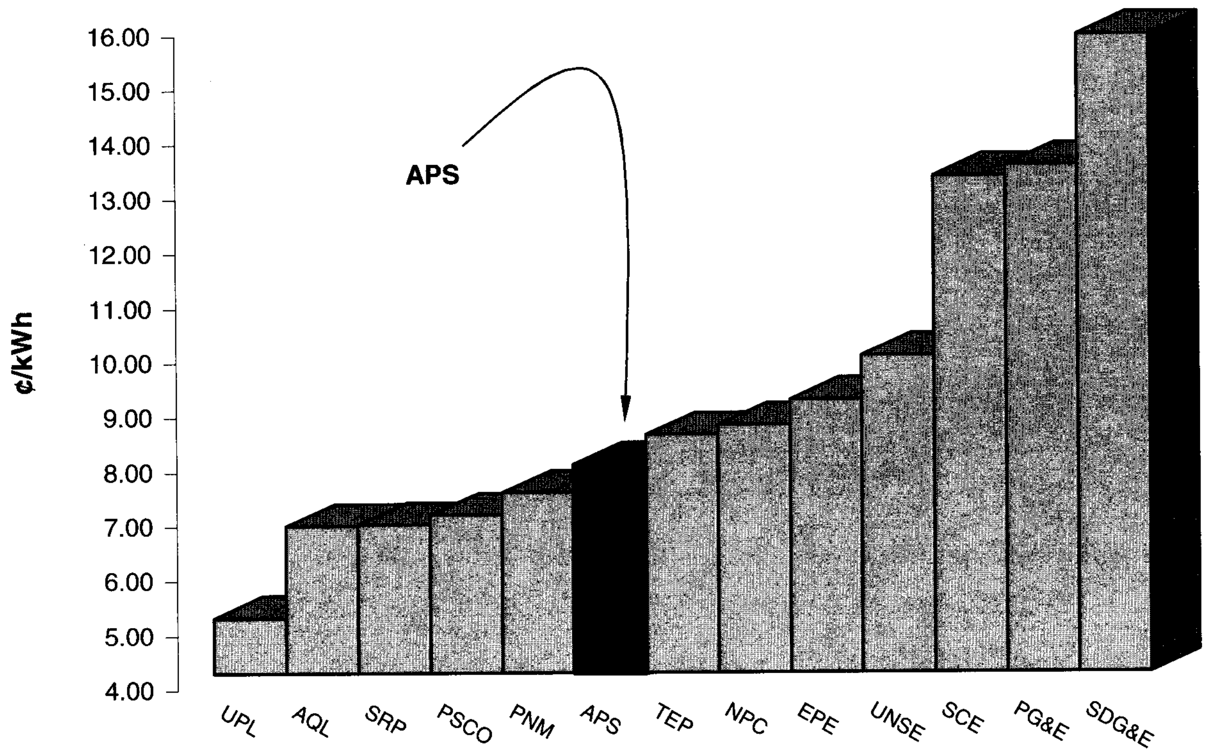


Utilities are: Utah Power and Light, Salt River Project, Aquila Networks - WPE (Colorado), Public Service of Colorado, Public Service of New Mexico, Arizona Public Service, El Paso Electric - New Mexico, Nevada Power Company, Tucson Electric Power, Unisource Electric, Southern California Edison, Pacific Gas and Electric, and San Diego Gas and Electric.

Source: Energy Velocity Database for 2003

APS EXHIBIT ____

Average Total Retail Prices
Western Utilities
Year Ending 12/31/2003



Utilities are: Utah Power and Light, Aquila Networks - WPE (Colorado), Salt River Project, Public Service of Colorado, Public Service of New Mexico, Arizona Public Service, Tucson Electric Power, Nevada Power Company, El Paso Electric - New Mexico, Unisource Electric, Southern California Edison, Pacific Gas and Electric, and San Diego Gas and Electric.

Source: Energy Velocity Database for 2003

Exhibit APS_____

EXHIBIT

APS-27

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ARIZONA PUBLIC SERVICE COMPANY
Example of the Impact on an Estimated Bill from a Lower Load Factor

	Load Factor	Rate	kWh Used To Estimate Demand	Estimated kW [3]	Base Bill
Estimated Bill [1]	45.0%	EC-1	1,571	4.7	$ 93.08
Estimated Bill [2]	35.0%	EC-1	1,571	6.0	$ 102.25

	Actual Load Factor	Rate	Actual kWh	Actual Demand	Base Bill
Actual Bill [4]	27.0%	EC-1	1,511	7.4	$ 110.23

[1] Based on load factor utilized for billing purposes pre 2002.

[2] Based on load factor utilized for billing purposes post 2002.

[3] Estimated kW calculation:

$$\text{kW} = \frac{\text{kWh}}{(\text{\# of days} * 24 \text{ hours})/\text{load factor \%}}$$

$$6.0 \text{ kW} = \frac{1571}{(31*24)/35\%}$$

[4] Based on March 2004 actual metered usage.

APS - 28 thru APS - 32

will be late-filed

exhibits.

EXHIBIT
APS-33
~~Admitted~~

Summary of Settlement Direct Testimony of Steven M. Wheeler

APS has reduced its prices nine times since 1991. These decreases took place during a period of unprecedented industry turmoil resulting in double digit increases by utilities throughout the country, and particularly here in the West. Unfortunately, we can no longer successfully continue to perform our mission without a price adjustment.

Our rapidly deteriorating financial position and our inability under current rates to earn a reasonable return that would attract and retain capital have left us with perilously low credit metrics. We also have "negative" outlooks from all major credit rating agencies. All this comes at a time when APS will need to invest hundreds of millions of new dollars in the next several years to provide critical infrastructure to serve our rapidly growing customer base. Existing debt from previous investments in plant and equipment will also have to be refinanced on a regular basis. Thus, we were compelled to seek what by all accounts should be perceived as a very modest rate increase – one that even if it had been granted in full would have set rates at the same level they were in the mid-1980s.

And just as our customers expect to receive value for what they pay for electric service, they expect that service to be reliable. They also expect APS to act in an environmentally responsible manner when conducting its business and to have programs in place for its economically disadvantaged customers. I believe customers understand that this will, from time to time, require higher prices.

As I indicated in my Rebuttal Testimony, regulation need not be seen as, and most often is not a "zero sum game," where every utility "gain" must be viewed as a customer "loss." The proposed Settlement is precisely such an example of a "win-win" outcome that meets the needs of customers (both residential and commercial), environmental groups, competitive wholesale and retail market participants, APS workers, low-income customer advocates, and, yes, the Company's investors.

APS had three primary goals going into this rate proceeding and in settlement discussions. In a nutshell, these goals were:

(1) FINANCIAL – We needed to preserve our financial integrity so that we could continue to attract upon reasonable terms the very substantial capital investment necessary to serve the second fastest growing service area in America;

(2) RELIABILITY– We needed to receive clarification on fundamental regulatory issues affecting resource acquisition and system planning that had become increasingly uncertain in the years since the 1999 APS Settlement was approved by Decision No. 61973 (October 6, 1999); and

(3) UNIFICATION AND EQUITY – We had to address the consequences of the Commission's "Track A" order in Decision No. 65154 (September 10, 2002), which halted the divestiture of APS generation to Pinnacle West Energy Corporation ("PWEC"), thus bifurcating the generation used to serve APS into two entities subject to differing regulatory regimes.

The settlement agreement filed by Commission Staff on August 18, 2004, was responsive to each of these goals to one degree or another.

The settlement also provides for numerous benefits to APS customers and to the people of Arizona. These include:

- a rate increase that, although significantly less than half of what the Company believes it could demonstrate through its testimony, moves each customer class closer to rates based on cost of service principles

- acquisition for the benefit of APS customers of some 1700 MW of PWEC generation at significantly less than cost and over half a BILLION dollars below its long-term economic value to customers

- implementation of rate adjustment mechanisms, several of which had been approved previously, in whole or in part, in Decision No. 66567 (November 18, 2003), to smooth out changes in rates over time, provide proper price signals, and reduce earnings volatility

- an over 14-fold increase in the level of investment in Commission-approved energy efficiency and conservation, programs, including expansion of the existing low-income weatherization program, and a mechanism for funding even greater amounts of these types of programs, as well as demand-response programs, if the Commission finds them cost-effective and appropriate

- an RFP in 2005 that could increase APS renewable capacity and energy by approximately 1100%

- a mechanism to fund additional renewable energy commitments ordered by the Commission as a result of its ongoing review of the Environmental Portfolio Standard ("EPS")

- an expansion in the APS low-income rate discount and bill assistance programs to insulate the Company's eligible low-income customers from the proposed increase

- to further promote the competitive wholesale market in the near term, a 1000 MW or greater competitive power solicitation will be held during 2005 in which no APS affiliate will be permitted to bid

- a "self-build" moratorium until 2015 and a prohibition on the ability of an APS affiliate to bid in any subsequent solicitation for long-term APS resources without the participation of an independent monitor selected by the Commission

- complete unbundling of rates to facilitate retail competition along with setting of rates for competitive electric services based on APS' cost of service so that competition will be based on the relative efficiency of the competitors and not on the arbitrage of an inefficient rate structure

- an opportunity for competitive retail electric service providers ("ESPs") to participate or for their customers to participate in the energy efficiency, conservation and renewable energy programs called for under either the agreement or the existing EPS

- to address long term development of the market and APS resource needs for the future, a series of workshops and, if appropriate, formal Commission rulemaking on competitive procurement processes, resource planning and infrastructure development

- confirmation that APS has clear authority to join a regional transmission organization ("RTO") or similar entity to facilitate more efficient wholesale competition

- implementation of a special rate structure recognizing the unique circumstances surrounding the receipt of electric service by Luke Air Force Base ("Luke"), which should also assist the ongoing efforts to prevent closure of Luke

- continued funding of nuclear decommissioning using a "greenfield" methodology in which the Palo Verde plant site is to be restored to its natural condition to the extent possible once the Palo Verde units are retired and dismantled

- an accounting mechanism that will allow for future funding of ongoing efforts by APS at bark beetle remediation, thus promoting system reliability, forest health and community fire safety

- a dismissal of all pending litigation by APS against the Commission and release of all claims as a result of the Track A Order, including but not limited to the $234 million write-off taken by the Company under terms of the 1999 APS Settlement

The process utilized during the nearly four months of intense settlement negotiations was the most open, transparent and inclusive I have seen in my nearly thirty years of practice and appearances before this and other regulatory agencies, both in and outside of Arizona. It also fully complied with both the letter and spirit of this Commission's current, if informal, settlement policy. Every view received fair and deliberate consideration in these negotiations. No doubt as a result of these unprecedented efforts at inclusion and good faith negotiation, we ended up with an agreement that covers the broadest possible range of issues, some of which were wholly outside the scope of any of the litigation positions taken by the parties or which presented entirely new solutions to known issues. I also dare say that the breadth of support evidenced for this agreement is unheard of in this jurisdiction, and to my knowledge, anywhere in the country. Staff, RUCO, consumer groups (large and small, residential and commercial, as well as low-income), APS' competitors (both wholesale and retail), and environmental advocates (both proponents of increased energy efficiency/conservation and renewable resources) all have united in support of the proposed settlement – not because any of them received all that they pursued in litigation, but because all of them believe this agreement is a fair resolution of complicated issues by parties having often conflicting goals and interests and, perhaps more to the point, a better overall resolution of such issues than would likely be achieved through continued litigation.

As I discuss, however briefly, each of the Sections of the Settlement in the body of my Direct Settlement Testimony, both the vast scope of the agreement and the delicate balance of compromises made to achieve it will become all the more evident. APS believes that each provision of the agreement serves an important purpose in the overall context of this Settlement and is presenting witnesses who can respond to questions on such provisions.

Arizona law is full of repeated statements supporting the use of negotiated settlement rather than litigation to resolve disputes. The more complex the dispute, the more likely it is that the parties most affected can better negotiate than litigate a resolution having broad acceptance as being a fair solution to difficult problems. Indeed, the entire legislative process, with which several of the Commissioners are quite familiar, is essentially one of negotiation, debate and compromise.

In making these observations about the role of negotiation and settlement in shaping public policy, I am in no way suggesting that the Commission should not satisfy itself and independently confirm that the public interest benefits promised by the parties to this Settlement actually exist and that there is nothing in the Settlement that harms the public interest. We recognize that this is not only the Commission's right, but also its obligation under our Constitution.

Response to Letter from Commissioner Mayes

On October 29, 2004, Commissioner Mayes filed a letter asking the parties to provide a comparison between their original "litigation" position and the position adopted by the parties in the Settlement. I have attached to my Summary an issue matrix doing just that. As is shown by that issue matrix, many of the Settlement provisions represented very significant concessions by the Company. In other instances, because the parties were fairly close to each other in the first instance, the Settlement's treatment of those issues is similar to the original APS request. And as I noted earlier in my Summary, the Settlement also addressed issues not raised by APS (or in some cases, not by the testimony of any party).

In the remainder of this Summary, I will discuss some of the major differences and similarities between the Company's original request and the Settlement. However, most of these matters are more appropriately a part of Mr. Robinson's Summary and that of Mr. Rumolo. Yet others are either sufficiently explained by the issue matrix itself or are not, in the Company's view, major substantive issues. Mr. Robinson's Summary is being submitted concurrently with my own. Mr. Rumolo's will be filed later in accordance with the Procedural Order of August 20, 2004. The issue matrix referenced above indicates the appropriate APS witness to respond to detailed inquiries concerning either the Company's original request (as it relates to the issue in question) or the corresponding provision of the Settlement.

To understand how we got to where we are in the proposed Settlement, one must first recognize that the Company and its affiliates were severely and negatively impacted by the "Track A" Order. The "Track B" process, which was a direct result of the "Track A" Order, also resulted in significant unrecovered costs for APS. As a result, APS had previously asserted a number of potential claims against the Commission and the State in the manner prescribed by Arizona law.

The Principles of Resolution entered into by APS and Commission Staff as part of the financing approved in Decision No. 65796 (April 4, 2003), required APS and its affiliates to forego all legal and equitable claims resulting from the unilateral modification by the "Track A" Order of the 1999 APS Settlement Agreement excepting: (1) APS' request to acquire and rate base at net book value the PWEC generation constructed to serve APS; (2) restoration of the $234 million write-off of prudently-incurred generation costs required by the 1999 APS Settlement Agreement; and (3) recovery of the costs incurred by APS to implement the Commission's Retail Electric Competition Rules and related orders. Each of these remaining APS claims was presented in the Company's original rate filing, and each is addressed in the proposed Settlement.

The first, acquiring and rate-basing the PWEC generation, was achieved in the Settlement only at great cost to APS and with significant restrictions on the Company's future resource procurement activities. Mr. Robinson discusses why APS could agree to these modifications of its request despite the existence of unequivocal evidence that acquiring the PWEC generation at its June 30, 2004 book value, as was originally proposed by the Company, was the best long-term resource option for APS customers.

Restoration of the $234 million write-off resulting from the 1999 APS Settlement Agreement is permanently denied in the proposed Settlement. At the time of that 1999 agreement, APS had only agreed to this write-off of costs already previously allowed by the Commission as fully recoverable in rates in exchange for certain other provisions of that 1999 agreement – provisions unilaterally modified by the "Track A" Order. Although it was both logical and equitable for that write-off to be restored under the circumstances, APS was willing to agree to this aspect of the proposed Settlement because of the parts of the proposed Settlement that provide some regulatory certainty both as to the PWEC assets and the future resource procurement efforts of APS. This latter point was critical to better defining the Company's ongoing obligation for its customers' future generation needs and the regulatory "rules of the road" regarding the efforts of APS to discharge that obligation.

There was virtually no disagreement over the recovery of costs related to the implementation of the Retail Electric Competition Rules and related orders. The proposed Settlement reflects the general consensus on this issue.

Although the proposed Settlement fell far short of satisfying even these few remaining claims for relief, APS has agreed in the proposed Settlement to dismiss with prejudice <u>all</u> "Track A" litigation – litigation seeking very significant damages. The Company and its affiliates also surrender any potential but presently unasserted damage claims arising from the "Track A".

Commissioner Mayes' October 29th letter also asks the parties to explain how the concessions made to achieve this proposed Settlement are "in the public interest." To that I would first note that the many parties to the proposed Settlement represent literally all segments of the affected public, thus providing the strongest possible evidence that this Settlement is in the public interest. Second, it is the Settlement as a whole that the parties believe and the Commission is asked to find is "in the public interest" rather than isolated provisions of that proposed Settlement. Obviously, APS would not believe it "in the public interest" for it to make, taken in isolation, all the concessions embodied by the proposed Settlement. Neither would it reasonably expect other parties to feel differently about the issues most important to them. What is "in the public interest" is that a widely divergent group of usually adversarial interests were able to find sufficient common ground to work out this unprecedented agreement – an agreement that represents the originally-desired outcome of no one but an acceptable outcome to virtually everyone. I am hopeful that the Commission will also conclude that this Settlement is in the public interest – not because APS and twenty-some other parties, including Commission Staff say so, but because I hope you will share our collective belief that the Settlement offers substantial benefits to our customers and to the State – benefits that could not likely be achieved through protracted adversarial litigation.

Major Issue Comparison
APS Case vs. Settlement Agreement

Issue	APS Rate Case Filing[1]	Settlement	APS Witness
Revenue Requirement	$175M (9.77%) increase (includes CRCC surcharge)	$75.5M (4.21%) increase (includes CRCC surcharge and $10M of required DSM expenditures)	Donald G. Robinson
Competition Rules Compliance Charge (CRCC Surcharge)	0.44% increase to test year revenue requirement in the form of a temporary surcharge; APS may recover $47.7M plus interest over 5 years	No significant change	Donald G. Robinson
PWEC Asset Treatment / Competitive Procurement of Power	Included in rate base at original cost less depreciation of $889M	Included in rate base at original cost less depreciation of $700M (includes $148M Track B disallowance and additional 6 months of depreciation); no future stranded costs for the PWEC assets; APS will not self-build prior to 1/1/15 without authorization by the Commission; RFP by end of 2005 for at least 1000 MW for 2007 and beyond	Steven M. Wheeler Donald G. Robinson
Cost of Capital	55-45 capital structure w/ PWEC assets	No change	Donald G. Robinson
	5.8% cost of debt	No change	Donald G. Robinson
	11.5% cost of equity	10.25% cost of equity	Donald G. Robinson

Major Issue Comparison
APS Case vs. Settlement Agreement

Issue	APS Rate Case Filing[1]	Settlement	APS Witness
Power Supply Adjustor	PSA to include fuel and purchased power costs and have no sunset provision; APS and customers to share in costs and savings (90% to customers, 10% to APS, APS' share capped at $20M); PSA to begin after June 30, 2004 per Decision No. 61973	APS to forego recovery of increased fuel and purchased power costs between 7/1/04 and 12/31/04; cap on APS share eliminated; detailed reporting requirements; PSA to have a minimum life of 5 years	Donald G. Robinson
Depreciation	Depreciation rates based on traditional service lives	Depreciation rates based on Staff's extended service lives	Donald G. Robinson
$234 Million Write-Off	Full restoration	No current or future recovery	Steven M. Wheeler
Demand Side Management	$3M per year for DSM programs (including low income) collected through a DSM surcharge	DSM expenditures of $48M on ACC-approved DSM programs over 3 years; $10M per year in base rates with the remainder recovered through DSM adjustment mechanism; collaborative of interested parties to identify and provide input on DSM proposals prior to submission to Commission for approval	Donald G. Robinson

Major Issue Comparison
APS Case vs. Settlement Agreement

Issue	APS Rate Case Filing[1]	Settlement	APS Witness
Environmental Portfolio Standard and Other Renewables Programs	Maintain current level of EPS funding and modify current EPS surcharge to allow for annual changes in funding to meet the current EPS requirements	Current EPS surcharge modified to accommodate future changes to EPS; 2005 Renewables RFP for at least 100 MW and 250,000 MWh plus 10% of incremental load growth	Donald G. Robinson
Regulatory Issues	APS sought clarification as to the responsibility of assuring adequate and reliable supplies for APS customers and the permitted structures and means by which that obligation should be discharged	The Settlement Agreement clarifies that (1) APS has the obligation to plan for and serve all customers in its service area, (2) changes in retail access are to be addressed through ECAG, (3) (subject to other conditions of the Settlement) APS has the ability to self-build or buy assets for native load and (4) APS may join a FERC-approved RTO.	Steven M. Wheeler
Low Income Programs	Maintain current programs and increase funding for marketing E-3 & E-4 tariffs	Increase E-3 and E-4 tariff discount levels	David J. Rumolo
Returning Customer Direct Access Charge	Consistent with Decision No. 66567	No change	David J. Rumolo
Service Schedule Changes	Proposed changes to Schedules 1, 3, 4, 7, 10 and 15	Changes to Schedules 1, 3, 4, 7, 10 and 15 as generally proposed by Staff	David J. Rumolo

Major Issue Comparison
APS Case vs. Settlement Agreement

Issue	APS Rate Case Filing[1]	Settlement	APS Witness
Nuclear Decommissioning Funding	Funding level determined using traditional, Commission-approved methodology	No change	Donald G. Robinson
Transmission Cost Adjustor	Proposed as rate schedule TCA-1 and relates to specific costs incurred by APS for procuring transmission for retail customers	Approved with 5% trigger over average test-year transmission costs	David J. Rumolo
Distributed Generation	Continuation of existing policies and practices	Staff to schedule workshops to discuss and resolve outstanding issues	Stephen J. Bischoff
Bark Beetle Remediation	Cost recognition sought	APS authorized to defer reasonable costs that exceed test year levels of tree and brush control	Donald G. Robinson Stephen J. Bischoff
Rate Design	Rate unbundling in conformance with Competition Rules; current frozen rate schedules eliminated; modification to time-of-use rates for General Service customers	Unbundled rate design structure similar to that proposed in APS filing; frozen rates to be eliminated in next rate case; modifications to relative class rates of return compared to APS filed case; maintain current time-of-use time periods for General Service rates; significant revisions to General Service rate E-32	David J. Rumolo

Major Issue Comparison
APS Case vs. Settlement Agreement

Issue	APS Rate Case Filing[1]	Settlement	APS Witness
Litigation and Other Issues	Not addressed	APS and affiliates to dismiss or forego with prejudice any and all litigation related to Decision No. 65154, the Track A Order and Decision No. 61973 (1999 APS Settlement); the Preliminary Inquiry ordered in Decision No. 65796 shall be concluded with no further action by the Commission	Steven M. Wheeler

[1] If APS modified its position on rebuttal, this column reflects that modification.

EXHIBIT
APS-34
~~Admitted~~

SUMMARY OF SETTLEMENT REBUTTAL TESTIMONY OF STEVEN M. WHEELER

Of the nearly thirty parties to this rate proceeding, only one has filed testimony in opposition. Even here, the AzCA has taken issue with portions of just two of the 22 sections of the proposed settlement. For my part, I wish to simply reiterate the Company's three fundamental positions with regard to the interconnection and operation of customer-owned generation on the APS system. The Commission should not mandate measures that:

(1) compromise system reliability;
(2) compromise employee or public safety; or,
(3) subsidize distributed generation with other customers' money.

EXHIBIT
APS-35
~~Admitted~~

Summary of Settlement Direct Testimony of Donald G. Robinson

The Settlement was reached after extensive and detailed negotiations involving essentially all of the parties to the case. One of the Company's primary goals going into this rate proceeding was to preserve its financial integrity so that it could continue to attract the capital required to maintain reliable service to our customers. Although I believe the Settlement should permit APS to maintain investment grade credit ratings, it does not provide APS the ability to improve those ratings, nor does it leave room for any further material decline in the Company's financial ratios. It also will not allow the Company to actually earn the agreed to return on common equity ("ROE"). For these reasons, the reactions of the financial markets to the Settlement were mixed, with some entities being neutral to marginally positive, and others expressing concerns about the modest level of the rate increase proposed in the Settlement. APS Witness Steven Fetter addresses the reaction of the market in more detail in his Settlement Testimony.

The Settlement adopts a Power Supply Adjustor ("PSA") similar to adjustment mechanisms approved by the Commission in other proceedings and to the PSA approved by the Commission in APS' PSA proceeding (*see* Decision No. 66567 (November 18, 2003)). The PSA is critical to the Company's and, I believe, the financial market's, ability to accept the low base rate increase. As discussed in greater detail in my Rebuttal Testimony and in the Rebuttal Testimony filed by APS Witness Peter Ewen, fuel and purchased power will make up almost half of the total Company operating expenses in 2005. This increasing exposure to forward gas and power prices, coupled with high price volatility, further illustrates the importance of the proposed PSA.

Although APS already had the lowest overall depreciation rates in Arizona, the Settlement further extends the service lives of many APS assets as recommended by Staff while adopting the jurisdictional net salvage allowance proposed by APS. This extension of service lives explains why the Company's agreement to forego stranded costs on the PWEC assets also represents a significant concession.

I also discuss two procurement processes that the Company will be implementing before the end of 2005 as a result of the Settlement. First, the Company will conduct a 2005 solicitation for at least 1000 MW of long-term resources, with deliveries to begin in 2007. PWEC will not participate in this solicitation. The Settlement also places restrictions on the Company's right to self-build generation through 2015.

Second, the Company will conduct a special RFP in 2005 seeking at least 100 MW and 250,000 MWh from various renewable resources for delivery beginning in 2006. In addition, the Company has agreed to seek to acquire 10% of its future incremental nameplate capacity needs from such renewables.

Finally, my testimony discusses the issues of nuclear decommissioning and the deferral for bark beetle remediation costs.

On October 29, 2004, Commissioner Mayes asked the parties to provide a comparison of their litigation and settlement positions. Mr. Wheeler has provided a matrix of these issues, and I will discuss a few of them.

After a detailed evaluation of the Company's financial status and its revenue requirement needs, the Company filed an application seeking a revenue requirement increase of $175 million, including the Competition Rules Compliance Charge ("CRCC"). In the Settlement submitted to the Commission, APS has agreed to a revenue requirement increase of only $75.5 million including the CRCC. The Company agreed to this reduced revenue requirement increase because we believe that the lower revenue requirement increase maintains the Company's financial integrity, a key driver in the Company's rate case application, although it leaves little room for any decline in the Company's financials. Furthermore, the settlement of this rate case resolves many complex and contentious issues in a reasonable manner and is in the public interest.

The Settlement revenue requirement increase is based on a reduced cost of equity from the Company's filing. In its filing, the Company sought an ROE of 11.5%, a 5.8% cost of debt, and a capital structure of 50% debt-50% equity, which resulted in an 8.67% cost of capital. The Settlement, however, reflects an ROE of 10.25%, a cost of debt of 5.8%, and a capital structure of 55% debt-45% equity, which results in a cost of capital of 7.80%. As I discuss in my Settlement Direct Testimony, APS will not actually earn this reduced return in 2005, even assuming that the Settlement rates could be implemented January 1, 2005. Thus, a pattern of earning less than what the Commission has found to be the Company's cost of equity will continue, with 2005 representing the 4th straight year of underearning by the Company totaling more than $220 million of underearning during that period.

In its filing, APS sought to rate base the PWEC Assets (Redhawk CC1 and CC2, West Phoenix CC4 and CC5, and Saguaro CT3) at projected cost of service as of June 30, 2004. At this level, those assets provide a significant benefit to APS customers. In the Settlement, APS has agreed to rate base the PWEC Assets at $700 million. That amount reflects a disallowance of $148 million from book value and is intended to reflect an estimate of the value for the remaining portion of the APS-PWEC Track B contract. Although the Company continues to believe that such a disallowance was not justified by the facts and because of the significant value that the PWEC Assets provide to customers at the rate base figure proposed in the Company's original rate filing, in the context of a global settlement, the Company agreed to the reduced rate base amount for the PWEC Assets.

In addition to agreeing to the disallowance on the PWEC Assets, the Company also agreed in the Settlement to two provisions critical to the merchant intervenors – the self-build moratorium and the competitive procurement process. Neither provision was addressed in the Company's rate case filing because the Company believed, and still believes, that the consolidation of the PWEC Assets into APS represents a great value to APS and our customers. APS also believed that it needed maximum flexibility to meet its customers' future generation needs in the most cost effective and reliable manner possible. However, Mr. Wheeler explains, the Company also saw significant value in reaching a global settlement of the rate case because of the certainty that it will bring not only to the Company, but also to the other parties. The competitive procurement called for in the Settlement will give the competitive wholesale market a clear opportunity to demonstrate whether or not it can deliver value to our customers, and we look forward to working with those in the merchant power industry to make this competitive solicitation and future competitive solicitations a success.

A key component of the Company's rate case filing, and critical to the Settlement submitted to the Commission, was not only the rate basing of the PWEC Assets, but also the PSA. All parties to the Settlement saw value in the PSA as proposed in the Settlement, which includes a 90/10 sharing and detailed reporting requirements, because it is critical to the Company's future economic stability and smoothes the impacts of volatile fuel and purchased power costs on customers.

With respect to depreciation, the Settlement adopts Staff's significantly longer service lives for many of APS' assets. Although longer service lives will lead to greater overall costs to customers over the life of the assets in question, it did reduce the revenue requirement in this case, and thus the Company agreed to them in the context of the settlement.

The Company included in its rebuttal case a proposal for $3 million per year for demand side management ("DSM"), including low income program funding, to be collected through a DSM surcharge. The Company also requested sufficient funding for the environmental portfolio standard ("EPS"). The Settlement, however, includes Commission approved DSM expenditures of $48 million over three years, with $10 million per year recovered in base rates and the rest recovered through an adjustment mechanism. Although the Company had reservations about its ability to actually spend such amounts in the time frames specified, it ultimately agreed to such a dramatic increase in DSM spending because of the broad array of issues otherwise resolved in the Settlement.

Finally, the Settlement adopts the Company's proposed nuclear decommissioning treatment, which is consistent with the Commission's prior decisions and reflects a "greenfield" approach to decommissioning and a deferral for future recovery of the reasonable costs of bark beetle remediation that exceed test year levels of tree and brush control.

Each of the issues I have discussed, as well as those discussed by Mr. Wheeler and Mr. Rumolo, played an important role in the Company's agreement to the Settlement. Each issue is also important to at least one or more of the other parties to the Settlement. Combined, the resolution of those issues in the Settlement submitted to the Commission for approval represents a significant achievement on the part of all of the parties and is in the public interest.

EXHIBIT
APS-36
Admitted

Summary of Settlement Direct Testimony of Steven M. Fetter

In this Settlement testimony, I discuss certain aspects of the settlement agreement that is under consideration by the Arizona Corporation Commission ("ACC" or "Commission") for review and approval. Specifically, from my perspective as a former state utility commission chairman and former head of the utility ratings practice at a major credit rating agency, I focus on the importance of settlements to the regulatory process and the benefits that can flow from them; the reasonableness of the 10.25% return on equity provision included within this settlement agreement; and the reaction of the Wall Street financial community, which generally appeared to view the settlement as a constructive resolution of the issues pending within the rate case, but also had some concern about the settlement's immediate impact on APS' financial condition. Finally, I conclude by explaining why I believe that approval of the settlement would represent a positive step for the regulatory environment within Arizona and why such approval could have a positive effect on the credit profiles of other regulated utilities operating within the Commission's jurisdiction.

EXHIBIT
APS-37
~~Admitted~~

Summary of Settlement Direct Testimony of David J. Rumolo

My testimony addresses three specific aspects of the Settlement. First, I describe the rate design aspects of the Agreement, including the proposed modifications to the residential and non-residential rates beginning with the unbundling of services in accordance with the Retail Electric Competition Rules ("Competition Rules"). The proposed rates for residential customers and key rates for non-residential customers are attached to the Agreement as Appendix J.

Second, my testimony describes two of the adjustment mechanisms that will become part of the APS electric tariff – the Transmission Cost Adjustment ("TCA") and the Returning Customer Direct Access Charge ("RCDAC"). The other adjustment mechanisms described in the Agreement, including the Power Supply Adjustment ("PSA"), the Demand Side Management Adjustment Charge ("DSMAC") and the Competition Rules Compliance Charge ("CRCC"), are addressed in the Settlement Testimonies of Steven M. Wheeler and Donald G. Robinson. Third, my testimony describes and explains the modifications to APS' Service Schedules to which the parties to the Agreement have reached concurrence. I have attached a series of tables that compares descriptions of the principle rate issues found in APS rate application with modifications to those issues as found in APS rebuttal testimony and the treatment of those issues in the Settlement Agreement.

From the perspective of rate design, I believe that the Settlement Agreement results in rates that represent a balance of the interests of the stakeholders represented by the signatories to the Agreement and is in the public interest. Retail rates are proposed that meet the requirements of the Competition Rules. Modest rate increases are proposed that also address the issue of class rate of return differentials. I urge the Commission to approve the Settlement Agreement.

	Filed Case	Rebuttal Testimony	Settlement Testimony
Residential Rates	Rates restructured in accordance with Competition rules; Schedule EC-1 eliminated; Schedule E-10 eliminated over one year period; Experimental TOU rate that would allow customers to pick alternative time periods; Elimination of TOU time periods in winter months.	EC-1 phased out over one year period, customer information process during phase-out period with an interim rate increase during phase-out. Non-time differentiated energy charges in winter proposed as alternative to staff. Increase in E-3 and E-4 discounts.	Schedules E-10 and EC-1 will be receive a slightly higher average rate increase compared to E-12, ET-1 and ECT-1R and will be eliminated in next APS rate case. TOU periods will be unchanged and APS will develop a report that addresses implementing flexibility in TOU rates. Experimental TOU rates will be adopted.
General Service Rate Schedules	Rates restructured in accordance with Competition Rules; simplification of Schedule E-32 including elimination of explicit demand charge for customers with loads of 20 kW or under; Schedule E-20 (Church rate) frozen to new customers; frozen/limited TOU rates eliminated and new TOU rate adopted. TOU time periods and seasons modified so the general service and residential rates have the same time periods. Voltage level discounts for primary and transmission level customers.	Modification of E-32 rate design to change billing break points; continue current TOU hours but adjust seasons to reflect same as residential	E-32 rate concepts as modified by rebuttal testimony adopted; Church rate frozen; existing TOU rates, except E-35, are frozen and will be eliminated in next rate case. New E-32 TOU adopted. Discount available for military bases served directly from APS substations.
Irrigation/Water Pumping Schedules	Elimination of Schedule E-38 and E-38-8T (approximately 160 customers), customers transferred to Schedule E-221, E-221-8T or E-32.		E-38 and E-38-8T frozen and will be eliminated in next APS rate case.
Street and Dusk to Dawn	Rate designs changed to a menu format to provide customers with more		

Lighting	choices.		
Partial Requirements Schedules	E-32 R reflects changes to E-32 since it is a billing option of E-32 that establishes minimum demand. Schedules E-52 and E-55 are unchanged, there are no customers on E-52 and E-55		

Power Supply Adjuster		Adopts sharing mechanism	90-10 Sharing Mechanism; charge will be implemented for the first time in April 2006, $0.004/kWh maximum adjustment each time; balancing account and potential amortization charge used to account for changes outside bandwidth; all off-system sales margins benefit ratepayers; monthly reporting to Staff
Transmission Cost Adjuster	TCA proposed to recover increased OATT costs and RTO costs when RTO is formed.		TCA trigger at 5% of test year costs
Returning Customer Adjuster		Impacts customers or aggregated groups over 3 Megawatts and would not apply if customer provides one year notice of intent to return to Standard Offer Service	
Competition Rules Compliance Charge			CRCC balance adjusted to reflect removal of RTO costs
System Benefits Adjustment		Proposed to use SBAC for DSM programs	Future use

Charge			
DSM Adjustment			Used to recover DSM program costs in excess of annual $10 million in base rates.
EPS Adjustment charge			Current surcharge converted to adjuster it allow for increased Commission funding.

Service Schedule 1	New charges and adjustment to existing charges	Acceptance of most modifications to changes recommended by ACC Staff	
Service Schedule 3	Line extension policy for individual permanent residential extensions modified to equipment allowance of $3,500 in lieu of footage allowance. Economic studies based on dual fuel assumption and only "wires" revenue.		Maintain current footage based policy. Economic studies based on dual fuel assumption and only "wires" revenue
Service Schedule 4	Allow totalizing for residential and single-phase general service, removal of prohibition of same-site remote totalizing.		
Schedule 7	Meter testing plan modified to recognize solid state metering and latest ANSI standards		
Schedule 10	Clean-up of language on direct access requirements		
Schedule 15	Specialized metering broadened to incorporate IDR and cost responsibility for specialized meters		

EXHIBIT

APS-38

Admitted

Summary of Settlement Rebuttal Testimony of David J. Rumolo

AzCA has made a number of inaccurate statements concerning the rates proposed under the Agreement. And although some of the changes suggested by AzCA would be advantageous to the AzCA's members and to the owners of distributed generation ("DG"), they would not be consistent with proper ratemaking and cost causation. Their impact on non-DG full-requirements customers of the Company would be both significant and adverse. The rate design proposed by the Agreement is balanced, progressive, and reflects a broad consensus of the customer groups that will actually be asked to pay the rates. Also, my testimony calls attention to the fact that the Agreement recognizes the need to finally address the issues raised by AzCA, by directing Commission Staff to resolve any outstanding distributed generation issues in workshops and, if necessary, rulemaking.

EXHIBIT
APS-39
Admitted

Summary of Testimony of Stephen J. Bischoff

My testimony addresses three specific aspects in response to the direct testimonies of Arizona Cogeneration Association ("AzCA") witnesses Peter F. Chamberlain, Robert T. Baltes, and William J. Murphy. First, I describe the previous work the Commission has done on distributed generation and summarize many of the key topics that were addressed by the Advisory Committee during the Commission's 1999 generic investigation of distributed generation and interconnection ("DGI") (Docket # E-00000A-99-043 1). This section also includes a summary of the work APS has done on distributed generation since the conclusion of the DGI workshops and final report. Second, my testimony discusses the impact of distributed generation on overall system reliability. Third, my testimony discusses APS' current interconnection agreements. These agreements are applied in a fair and equitable manner to ensure that interconnections are completed in a safe and timely manner. Such agreements also appropriately recover the cost of any necessary utility studies. This section of my testimony also discusses APS' support of a statewide standardization of interconnection requirements and the potential inclusion of IEEE-1547 standards into the existing APS interconnection requirements.

Although APS' current interconnection requirements are appropriate and effective, I believe the distributed generation issues brought in the AzCA witness's testimony should be fully addressed in Commission-sponsored workshops as specified in our current Agreement. This allows everyone with an interest in distributed generation technologies to participate in the development of key issues/findings that can be standardized and used in any needed rulemaking on distributed generation and be applied consistently by all regulated utilities in Arizona. Furthermore, APS supports distributed generation and the need to continue monitoring this technology while looking for opportunities where the installation of either customer-owned or utility-owned distributed generation meets all requirements for safety and reliability, and is cost-neutral for our non-DG customers.